Advice to the AER

AER's Preliminary Decision for SA Power Networks for 2015-20 and SA Power Networks' Revised Regulatory Proposal

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1 Introduction

1.1 Background and context

1.1.1 Context of advice to the AER

As a member of Consumer Challenge Panel Subgroup #2 (CCP2), I appreciate the opportunity to provide the Australian Energy Regulator (AER) with further advice on the AER's Preliminary Determination (PD) and on SA Power Networks' revised regulatory proposal, which responds to the AER's PD. In providing this advice, I have also taken account of the following material:

- The AER's Preliminary Determination for SA Power Networks 2015-20 (AER PD);
- The Revised Regulatory Proposal for 2015-20 by SA Power Networks;
- The presentations by Mr Bruce Mountain and Bev Hughson at the Public Forum (December 2014) and Pre-determination Conference (May 2015);
- The two submissions by CCP2 members (Mr Bruce Mountain and Bev Hughson) in response to the SA Power Networks' original proposal;
- The submissions by various stakeholders to the AER's PD and to SA Power Networks revised regulatory proposal; and
- The advice by CCP2 member, Mr Bruce Mountain, to the AER on the assessment of weighted average cost of capital (WACC) in the AER's PD.

Mr Mountain's advice to the AER on its approach to the assessment of WACC in the PD should be read in conjunction with my advice herein. The focus of my advice to the AER in this paper will be on the following aspects of the AER's PD and SA Power Network's revised regulatory proposal:

- Some general rules and principles which I consider should guide the AER in its assessment of SA Power Networks revised regulatory proposal;
- The AER's preliminary decision on the revenue and network price path for standard control services (SCS), and SA Power Networks' response;
- The AER's preliminary decision on the capital expenditure (capex) allowance for SCS and SA Power Networks' response; and
- The AER's preliminary decision on the operating cost (opex) allowance for SCS and SA Power Networks' response.

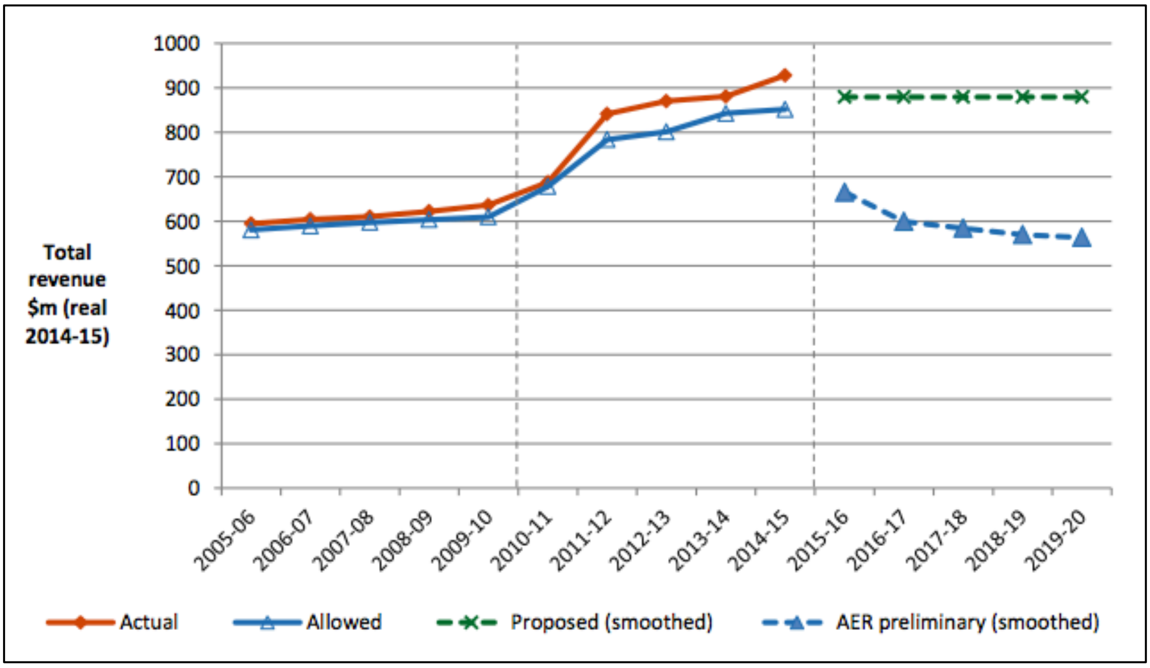
1.1.2 Context of the AER's PD and SA Power Network's revised proposal

The AER's PD and SA Power Networks revised regulatory proposal cover the regulatory control period (RCP) 2015-16 to 2019-20 (2015-20). The AER's PD has already delivered very substantial savings in the 2015-16 electricity prices to South Australian

(SA) households and businesses. These savings were particularly opportune at a time of economic uncertainty in South Australia (SA).
The AER's PD also presaged further reductions of nearly 10 per cent in average network prices for 2016-17 and pricing stability for the remainder of the RCP.

Figure 1.1 summarises the differences in revenue path between the SA Power Networks' original proposal and the AER's PD.

Figure 1.1: SA Power Networks' total proposed revenue and AER PD ($ million, 2015)



Source: AER, *SA Power Networks Distribution, Preliminary Determination 2015-20*, Overview, April 2015, Figure 1, p 8. Note: SA Power Networks proposed revenue is from its original proposal.

The reductions in average network prices arising from the AER's PD are very significant. Given the submissions to the AER by both SA businesses and consumers, the reductions in network prices have come as a welcome relief to electricity consumers, although CCP2 understands that the reductions in network prices have not been equally distributed across all classes of customers in 2015-16.

The AER's Final Determination (FD) for 2015-20 in October 2015 will revisit the AER's PD in the light of SA Power Networks' revised regulatory proposal and the various submissions to the PD and the revised proposal and the AER's additional analysis.

While the AER's FD will not directly affect 2015-16 electricity network prices, it will have an impact on network prices for the remaining four years of the regulatory period. That is, the FD may result in lower prices compared to the PD. Alternatively, if the AER decides that SA Power Networks revised proposal has some merit, network prices may be higher than in the PD from 2016-17.

It is even possible that these higher prices will include some "claw back" of the reductions in prices already delivered to SA business and residential consumers in 2015-16.

Unfortunately, while this regulatory process allows an appropriate level of consultation, it does create an extended period of uncertainty for SA businesses and consumers about the direction of electricity prices over the next few years. Further uncertainty about future networks prices arises from the current appeals to the Australian Competition Tribunal (Tribunal) initiated by the NSW and ACT distribution network service providers (DNSPs) and separately, by a NSW consumer representative body, the Public Interest Advocacy Centre (PIAC).

It is probable that the Tribunal's findings will also be relevant to the AER's decision on SA Power Networks' revenue allowance. However, SA consumers will not know the outcome of these appeals, nor will they know the implications of the appeal on the final prices for SA consumers beyond 2015-16.

1.2 SA Power Networks' Revised Regulatory Proposal for 2015-20 (July 2015)

Irrespective of the outcome of the appeals to the Tribunal, CCP2 notes that SA Power Networks' revised regulatory proposal includes an increase of over $1,300 million ($ nominal) in SA Power Networks' revenue compared to the AER's PD.

This in turn will result in some dramatic increases in average network prices in the period 2016/17 to 2019/20, including a "claw back" of the 2015-16 price reductions. In other words, SA Power Networks' revised proposal will effectively negate the savings to consumers of the AER's PD as illustrated in Figure 1.2.

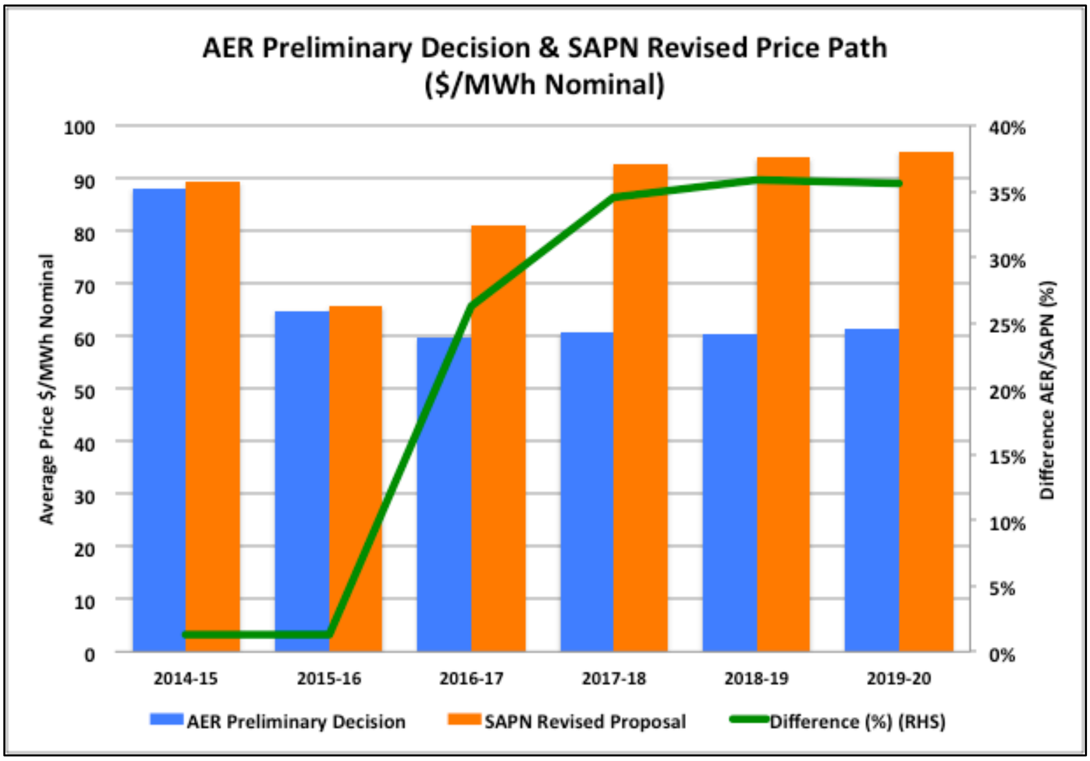
Figure 1.2 illustrates the average network price path ($ nominal) under the AER's PD and under SA Power Network's revised regulator proposal. It also provides an assessment of the annual percentage difference between the average prices from the PD and revised proposal. From 2017-18, the differences in average network prices are close to 35 per cent in each year.

Therefore, one of most important questions facing the SA community is whether SA Power Networks has justified this additional revenue and the resulting increase in average network prices as being in the long-term interests of SA electricity consumers. In making this assessment it is important to look at the interests of the community as a whole, as most consumers in SA "share" the additional costs under a common pricing regime.[1]

[1] "common pricing regime" means that there is a common network price for a particular class of customers across all customers irrespective of their location and associated cost to supply network services (excluding some very large customers). Common prices apply to both distribution network and to network use of system charges (NUOS =distribution + transmission

The AER's network price path and SA Power Networks' revised price path must also be considered in the context of the very significant reductions in the cost of capital. The advice provided by Mr Bruce Mountain indicates that the cost of capital allowance in the AER's PD is higher than is necessary. Nevertheless, there is a significant decrease in the AER's cost of capital compared to the 2010-2015 previous regulatory control period. This drop in the capital "disguises" the impact of increases in other areas of expenditure. However, if and when interest rates increase SA electricity consumers will feel the full effects of higher expenditure allowances.

Figure 1.2: AER Preliminary Determination & SA Power Networks' Revised Average Price Path



Source: AER Preliminary Decision SCS PTRM.xls (revenue summary/price path analysis $ nominal/revenue cap price path); SA Power Networks, Revised Proposal PTRM (revenue summary/price path analysis $ nominal/revenue cap price path).
Note: The slight differences in 2014-15 and 2015-16 average prices reflect the impact of small differences in the energy use for 2014-15 and 2015-16 under the revenue cap control mechanism. The 2015-16 average prices are based on published prices and reflect the AER's PD.

In contrast to SA Power Network's proposal, the expenditure allowances in the AER's PD are very much "status quo" decisions. This is more appropriate than expenditure increases particularly given that demand is not growing and other input costs of labour and materials are relatively flat.

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charges) despite the differences in transmission prices for different regions in SA except for large business customer categories where transmission charges are a direct pass through charge.

Commensurate with this scenario, the AER's PD allows only small increases in overall capital expenditure (capex) and operating expenditure (opex). I discuss these expenditures in detail in Sections 5 and 6 of this advice to the AER including where there are opportunities for furher reductions in the AER's capex and opex allowances, and a number of instances where the AER could revisit their decision not to accept SA Power Networks' revised proposal.

SA Power Networks revised regulatory proposal has reinstated many of the elements of expenditures set out in its original proposal, particularly the cost of capital and additional capex and opex compared to actual expenditure outcomes. SA Power Network's generally explains this additional capex and opex by reference to its customer engagement (CE) research and a view that regulatory obligations have increased.

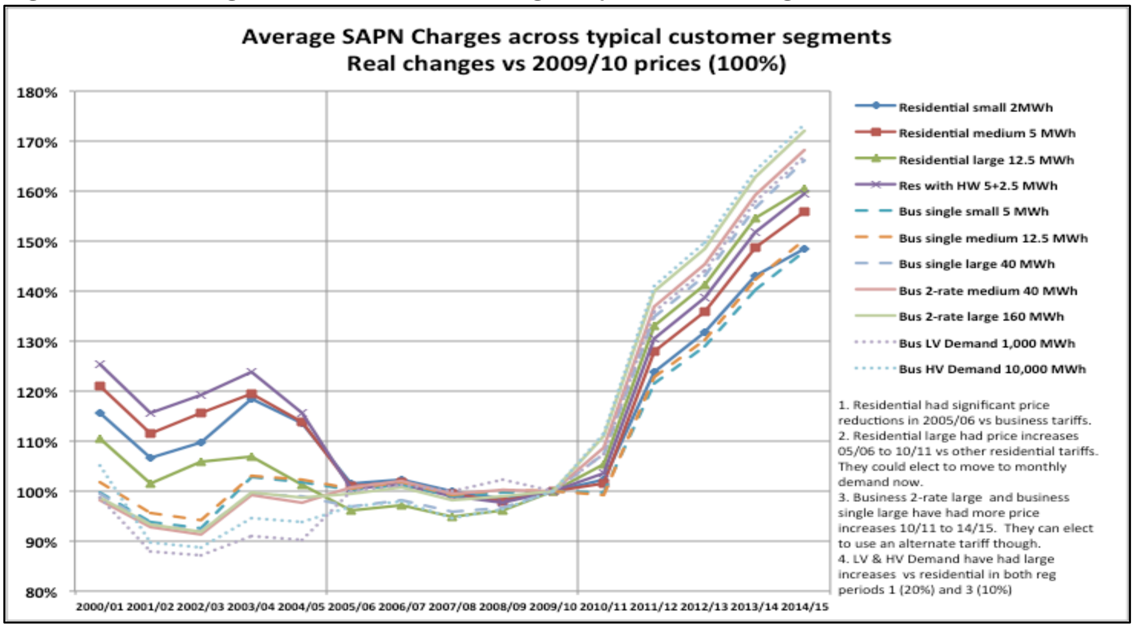
SA Power Networks also continues to propose significant increases in its depreciation costs and adjustments to imputation allowance that have the effect of increasing its taxation allowances, although these matters are not discussed in this current advice to the AER.

My assessment of these factors will also take into account the broader context in which the current regulatory decision is being made. In particular, it is not possible to consider SA Power Networks' original regulatory proposal, or its revised regulatory proposal without reference to:

- The changes in electricity demand over the last few years and the continued reductions in average usage per customer that is projected for 2015-20 RCP;
- The relatively benign regulatory environment in SA, with the SA Government and regulatory authorities such as the Essential Services Commission of South Australia (ESCoSA) and the Office of the Technical Regulator (OTR) all concerned to limit cost pressures on the business; and
- The rapid rise in average network real dollar prices over the 2010-15 RCP.

Figure 1.3 illustrates the network price changes. The rapidity of the changes in network prices over 2010-15 is particularly notable and has been felt by small and large customers alike.

Figure 1.3: Average SAPN network charges by customer segment (2000-1 to 2014-15)



Source: SA Power Networks, customer prices history tariff data model, xls.

These higher prices were driven by higher allowances for return on capital in 2010-15 RCP, but also significant increases in the capex and opex allowances justified in part by a need to upgrade the network assets and supporting assets such as IT systems and operating activities such as vegetation management.

Given the significant increases in expenditure allowances (in real dollar terms) for 2010-15 RCP, I consider that those expenditures (with some exceptions) provide a starting point for the assessment of expenditure allowances for the 2015-20 RCP. In addition, given the rise of rooftop PV and falling or flat electricity demand, I consider that it is as essential that SA Power Networks responds to these challenges by placing a real focus on expenditure controls for both capex and opex. For example, spare capacity in the network has already increased and any further capex growth risks additional redundancy, which must be avoided.

Overall, therefore, I expect that expenditure allowances by the AER should remain reasonably constant with some allowance for increasing opex efficiency as capex investments drive down costs. Given that there has been a very significant decline in the cost of capital, network prices should also decrease from the high points reached in 2014-15. That decrease should be also sustained across the whole regulatory period. Such reductions will enable a more sustainable network business in the future for the long-term interests of consumers.

It is concerning that SA Power Networks' revised proposal does not provide relief to consumers, rather it reinstates the original prices. In effect, the revised proposal "locks in" the high real prices seen in 2014-15, including a "claw back" of the relief that consumers have experience in 2015-16.

As indicated above, the advice provided herein to the AER concentrates on the general regulatory principles, network price paths and the capex and opex allowances. Although much could be said about SA Power Networks' proposed approach to depreciation and dividend imputation, CCP2 leaves those issues to the expertise of the AER and its consultants. However, in general the AER's position on both these issues is to be preferred

As part this response to the AER's PD and SA Power Network's revised proposal for capex and opex, I also touch on the use of CE research by SA Power Networks and, in particular, the use of the CE research as a justification for additional expenditures that are significantly above historical expenditures.

I consider that the CE research can be useful to SA Power Networks in determining its priorities and, possibly, to regulators when considering regulatory standards and targets. However, the CE research must be seen in the context of the regulatory framework and the broader institutional responsibilities.

In particular, I will highlight that the National Electricity Rules (NER) have been amended by the Australian Energy Market Commission (AEMC) in 2013 to clarify that the AER's responsibility is to set expenditures to meet demand, comply with the relevant regulations and maintain the safety of the network. It does not envisage expenditure allowances that go beyond these requirements.

A number of the issues discussed in this submission have already been canvassed in CCP2's previous formal advice on SA Power Networks' original proposal. We consider that CCP2's previous advice as relevant for the purposes of the AER's FD. We also consider that the various presentations prepared by CCP2 are relevant documents.

In particular, I refer the AER to the two papers by my fellow CCP2 member, Mr Bruce Mountain, that have been separately submitted to the AER. These two papers include, inter alia, a critical assessment of the AER's approach to the WACC and should be read in conjunction with my advice on the expenditure allowances that is set out herein.

In the remainder of this advice to the AER, at various points the text refers to "CCP2's analysis". However, as the author of the paper, I take full accountability for the accuracy of the analyses and the recommendations in the advice that follow from the analyses.

2 Summary & Recommendations

2.1 Overview of AER PD and SA Power Networks' revised regulatory proposal

The AER's PD made very significant reductions in SA Power Networks' proposed rate of return, depreciation, capital and operating expenditures and imputation allowances. As a result, the AER reduced SA Power Networks' overall revenue allowance by some 32 per cent for the 2015-20 RCP. This reduction provided scope for real price reductions in the order of 28 per cent in the first year of the RCP, 2015-16.

SA Power Networks' revised regulatory proposal has rejected many of the decisions in the AER's PD. As a result, SA Power Networks' revised revenue proposal is some 29 per cent increase compared to the AER's PD. Table 2.1 summarises the differences between SA Power Networks' original proposal and AER's PD, and the revised proposal and AER's PD.

Table 2.1: Comparison of total revenue allowance 2015-20 between AER and SA Power Networks' proposals ($ nominal)

	SAPN Original Proposal compared to AER PD (% above AER)	SAPN Revised Proposal compared to AER PD (% above AER)
Return on Capital	32	23
Operating Expenditure	21	12
Regulatory Depreciation	43	49
Net Tax Allowance	54	56
Annual Revenue	**32**	**29**

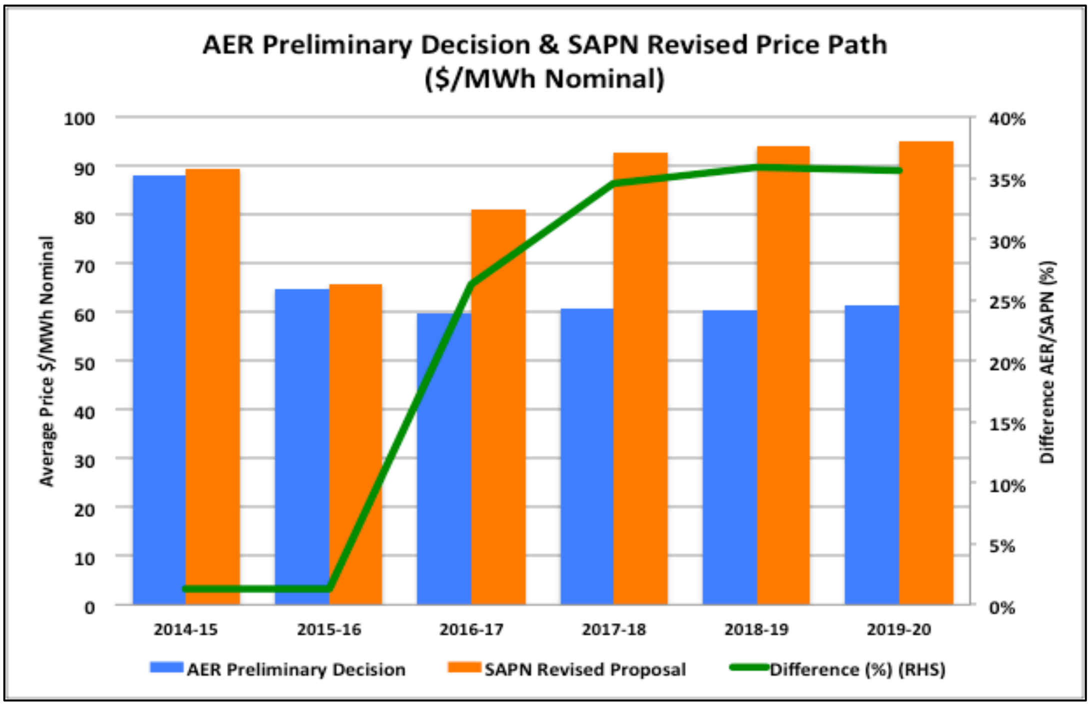
Source: SA Power Networks, *Revised Proposal 2015-20,* (Tables 16.2 and 16.3), CCP2 analysis. Note: the AER has slightly different figures for capital expenditure due to treatments of overheads. CCP2 has relied on the information in SA Power Networks' revised proposal for consistency in presentation.

Table 2.1 also demonstrates that there are significant differences between the AER and SA Power Networks across each component of the regulatory building blocks.

As a result, SA Power Networks proposed network prices will increase substantially from 2016-17, and by 2017-18 network prices will be nearly 35 per cent higher than they prices forecast under the AER's PD.

Figure 2.1 illustrates the differences between the AER's PD and SA Power Networks' proposed price path. CCP2 is aware of many submissions from SA electricity consumers and their representative groups who have expressed a great deal of concern about SA Power Networks' proposed price increases and have urged the AER to implement its PD price reductions for the remainder of the regulatory period.

Figure 2.1: AER Preliminary Determination & SA Power Networks Revised Average Price Path



Source: AER Preliminary Decision SCS PTRM.xls (revenue summary/price path analysis $ nominal/revenue cap price path); SA Power Networks, Revised Proposal PTRM (revenue summary/price path analysis $ nominal/revenue cap price path), CCP2 Analysis.
Note: The slight differences in 2014-15 and 2015-16 average prices reflect the impact of small differences in the energy use for 2014-15 and 2015-16 under the revenue cap control mechanism. The 2015-16 average prices are based on published prices and reflect the AER's PD.

2.2 Summary of CCP2's response to the AER's PD and SA Power Network's Revised Regulatory Proposal

2.2.1 Relevant rules and regulatory principles

The AER's PD establishes a number of important rules and principles in its review of SA Power Networks. They have particular application when considering SA Power Networks' proposal to substantially increase expenditure compared to previous RCPs on the basis of its CE program and its claim that the NER and other regulatory documents also require this additional expenditure.

Important rules and principles identified in this submission include, inter alia, the following:

- The AEMC's 2013 amendments to the NER to clarify the requirements under the expenditure objectives and criteria;[2]
- The AER approves total expenditures for capex and opex rather than individual projects;

[2] See in particular, amendments to NER, 6.5.6 (a)(3) and 6.6.7 (a)(3).

- An NSP's Board and management are responsible for how the AER's total capex and opex allowances are spent;
- Electricity consumers should not fund all network activities when these are conducted in the broader community interests;
- Capex and opex that improve a NSP's efficiency are not, per se, costs that can be passed through to electricity consumers; the incentive regulatory framework is an important consideration in assessing the overall costs and benefits of an efficiency project; and
- Applying the "competitive market" test to understand what costs are reasonably passed through to consumers.

CCP2 supports the AER in applying its interpretation of the rules and principles. In this submission we use these same principles to dispute a number of claims by SA Power Networks that the various regulations have changed significantly enough to require additional expenditures for compliance.

For example, we consider that SA Power Networks has overstated the changes to the NER, the national health and safety regulations, the requirements from ESCoSA and OTR and the nature of its obligations under its SRMTMP.[3] CCP2 values the submission from the SA Government that clarifies a number of these issues.

Similarly, SA Power Networks has used its CE research to support its additional expenditures but has done so without recognising the practical limitations of the CE research and its application to the 'real world' of investment in long-lived assets. For example, the CE research presented the narrow range of options when compared to the reality of complex expenditure and policy decision-making.

Moreover, SA Power Networks has not taken adequate account of the feedback from the community and their representatives in response to SA Power Networks' research and regulatory proposals. For example, in the revised regulatory proposal, SA Power Networks has been quite dismissive of the feedback from well-informed industry and consumer representatives. As a result there has been expressions of some frustration from a number of parties.

SA Power Networks does point out that the NER states that in making its expenditure decision, the AER must have regard to electricity consumers' concerns identified in a network's consumer engagement program.[4] However, this factor is just one factor amongst 11 factors that the AER must balance in order to best satisfy the overall capex and opex expenditure objectives and criteria in the NER.[5]

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[3] Safety, Reliability, Maintenance and Technical Management Plan. Generators and electricity and gas network service providers in SA are required to produce a SRMTMP which is reviewed by OTR and approved by ESCoSA. The SRMTMP is generally a high level document.

[4] NER, 6.5.6 (e) (5A) and 6.5.7 (e) (5A).

[5] See NER, 6.5.6 (a)-(c) and 6.5.7 (a) – (c).

CCP2 therefore supports the AER's cautious approach to the inclusion of CE research, particularly where the CE findings are not consistent with other aspects of the regulatory task. Nor is it consistent with feedback from various research participants and consumer representative groups, as noted above.

However, in this advice to the AER, there are a number of areas where the CE research may provide a valuable contribution. For instance, it might be useful to SA Power Networks' in prioritising different projects within the revenue constraints. It might also be useful information if SA Power Networks' considers that regulators should set tighter standards for network performance so that outcomes better align with the consumers' preferences SA Power Networks' claims have been identified through the research.

2.2.2 CCP2's views of the AER's PD

Although CCP2 agrees generally with the AER's application of the principles and rules set out above, the AER's PD is still essentially a conservative determination, albeit a considerable improvement over SA Power Networks' original and revised proposals. The AER's PD is considered conservative in the sense that:

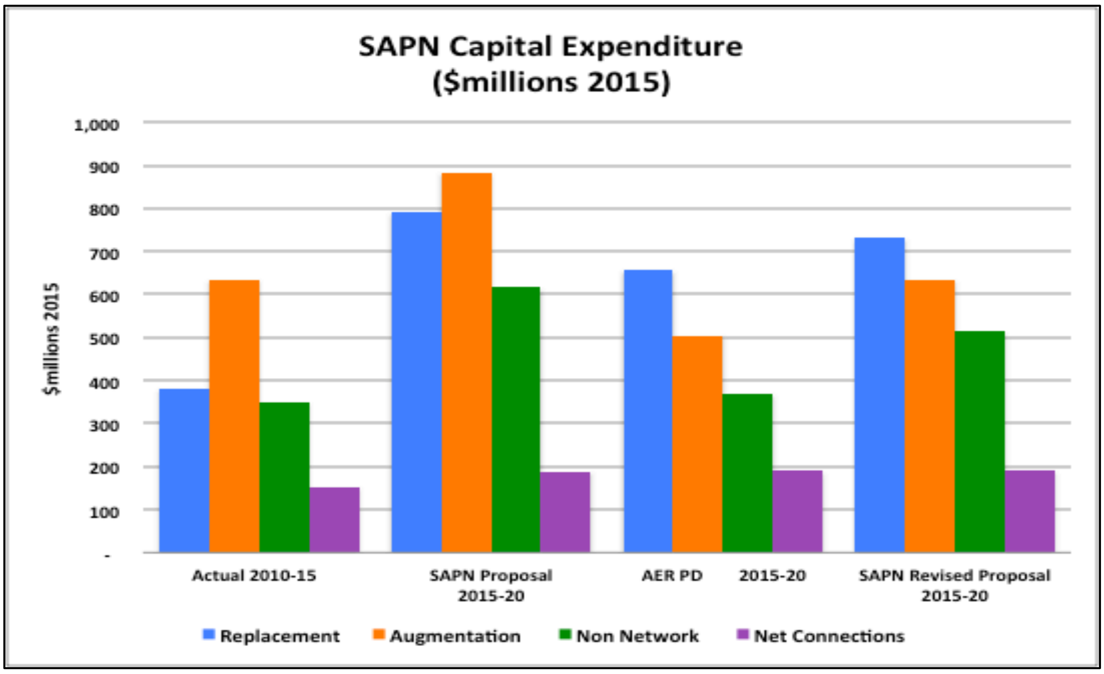
- **Rate of Return**: The AER has allowed SA Power Networks a rate of return that is above the efficient cost of capital and does not benchmark well with decisions by other regulators with respect to parameters such as the debt risk margin and the equity beta. CCP2 member, Mr Bruce Mountain, discusses these issues further in a separate submission.

- **Capex allowance**: The capital expenditure allowances has provided higher than necessary allowances for replacement capex and demand based augmentation capex in particular. The replacement capex under the AER's PD is much greater than existing actual replacement capex. However, the AER's rejection of other incremental capex proposals, including the substantial increases related to "safety" capex, principally bushfire management capex is supported by CCP2.

  Figure 2.2 illustrates the differences between the AER's PD, actual capex and SA Power Networks original and revised proposals by capex category. While the AER has reduced augmentation capex compared to 2010-15 RCP (reflecting the minimal growth in demand and customer numbers), the AER has increased its allowance for replacement and non-network expenditure.

  CCP2 acknowledges that SA Power Networks' downstream assets are aging (as nearly all capex in 2010-15 went to upstream asset replacement. However, there are real questions on whether the rate of replacement is too high (noting reliability is not affected at this stage). In any case, as so much of the upstream asset base has been replaced, SA Power Network's funds can be directed at the down stream assets if SA Power Networks chooses to prioritise these.

Figure 2.2: AER's PD and SA Power Networks' actual and proposed capex ($ million 2015)



Source: SA Power Networks, *Revised regulatory proposal 2015-20*, July 2015, Table 7.1 & 7.4, AER PD April 2015, CCP2 analysis.

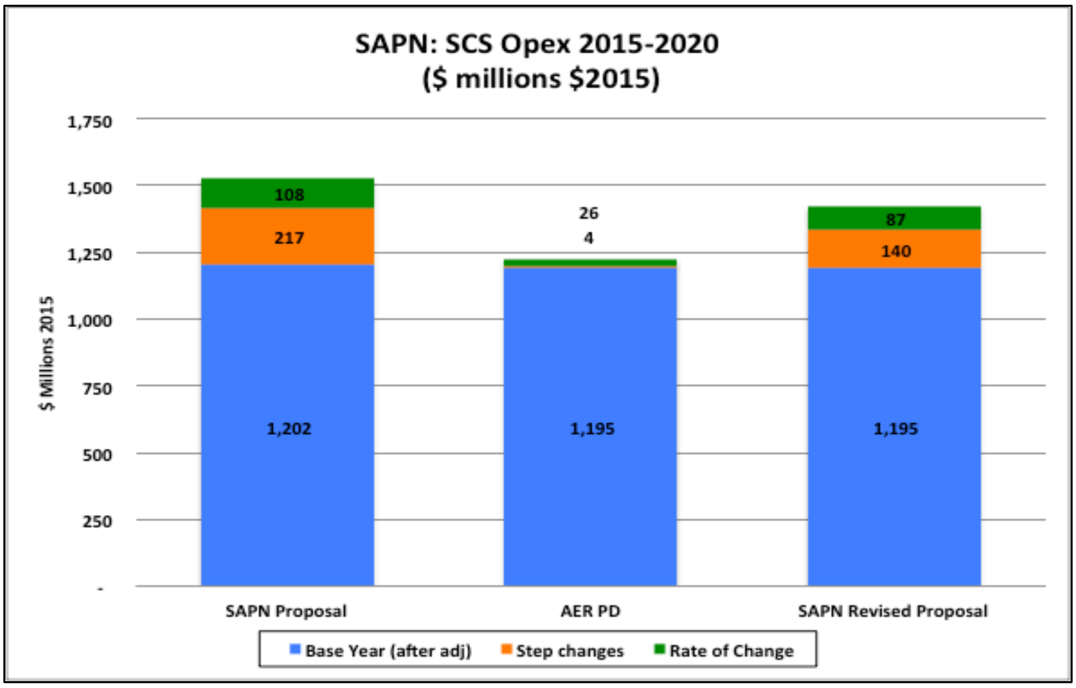
- **Strategic Projects**: The AER has allowed additional capex for projects that are essentially contingency projects, in particular the laying of a second electricity cable to Kangaroo Island that is still subject to a RIT-D assessment process before it can proceed. CCP2 is not satisfied with the AER's claim that the CESS will recover this amount if the project does not proceed; the CESS is a clumsy instrument for managing this risk.

- **Opex allowance**: the AER's operating expenditure allowance did not sufficiently examine SA Power Networks base year expenditure (2013-14) to ensure it was an efficient base given the significant decline in efficiency performance on the AER's measures since 2006. CCP2 is also concerned that, knowing efficiency had declined, the AER did not include a positive productivity factor in the forecast of opex. However, CCP2 considers that the AER's position on rate of change and step changes is generally well supported.

  For example, CCP2 is pleased that the AER has cut back on SA Power Networks' proposed vegetation management, particularly given that the proposal appears to add another $ 7 million to the base year that is already inflated by the pass through allowance granted for unique vegetation growing conditions and supposedly ending in 2014-15.

  Figure 2.3 summarises the AER's PD, SA Power Networks' actual expenditure for 2010-15 RCP and its original and revised regulatory proposals.

Figure 2.3: AER's PD and SA Power Networks' actual and proposed opex ($ million 2015)



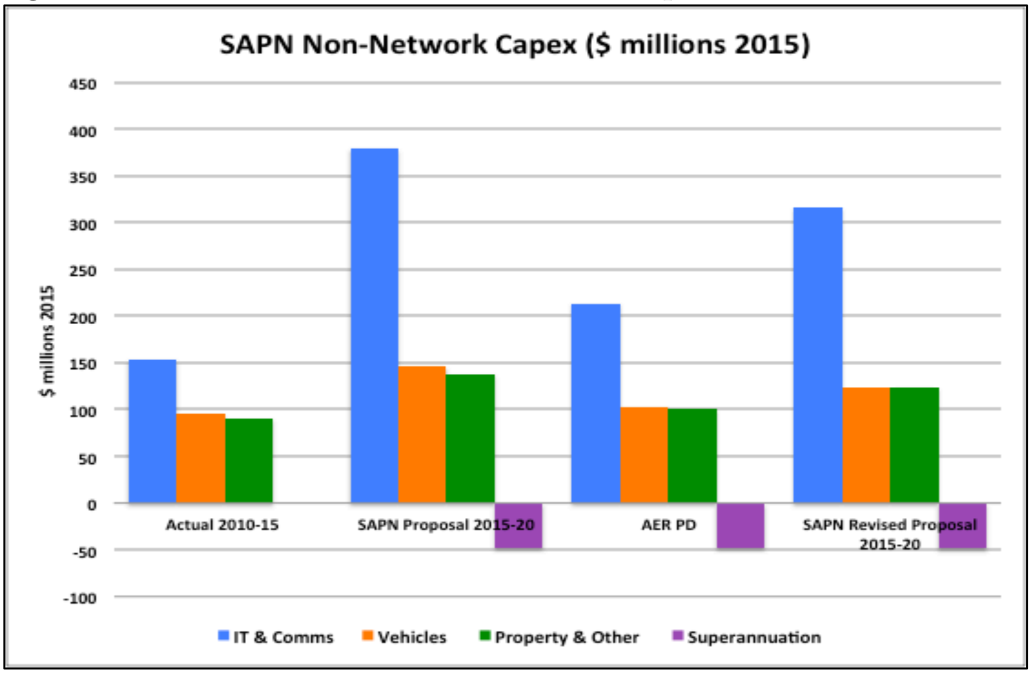
Source: SA Power Networks, *Revised Regulatory Proposal 2015-20*, Tables 8.1, 8.4 & 8.5. Excludes debt raising costs.

- **Non-network capex:** CCP2 considers that the AER's PD sets a reasonable allowance for the components of non-network capex. While IT capex is higher than in the 2010-15 RCP, CCP2 recognises the need to replace a number of SA Power Network's systems. However, CCP2 wants more assurance that there will be capex and opex savings in the future (during and beyond 2015-20 RCP) that is shared with the consumers who fund the investment. A new CIS and CRM system (properly specified in the tender) will facilitate lower cost adaption to regulatory changes such as cost reflective pricing and competition in metering. We do not see the level of savings that might be expected given the past and present expenditures.

  Figure 2.4 illustrates the AER's PD in comparison with actual capex on non-network investments and SA Power Networks' original and revised proposals for 2015-20.

- **Inconsistency between expenditures and outcomes**: CCP2 considers that the AER has conducted insufficient assessment of the overall impact of both previous and proposed expenditures on the level of forecast expenditures for 2015-20 RCP. For instance, SA Power Networks' significantly increased its replacement capex and its augmentation of upstream assets in 2010-15 RCP. However, there does not seem to be commensurate reductions in opex, or improvements in reliability. Similarly, the AER's PD provides a further allowance for replacement capex; however, we do not see commensurate cost reductions or performance improvements even in priority areas.

Figure 2.4: SA Power Networks' Non-Network Capex, Actual and Forecast



Source: SA Power Networks, *Regulatory Proposal*, October 2015, pp 231-249; SA Power Networks *Revised Regulatory Proposal*, July 2015, Table 7.26, pp 140-141, AER, *Preliminary Determination*, April 2015, Attachment 6, pp 6-109 – 112; CCP2 analysis. Note: 2010-15 superannuation costs are not included but it is suggested they are much the same as 2015-20.

While CCP2 considers that that the AER's PD is overall more conservative than is required to satisfy the NER requirements, there are a number specific items identified in SA Power Networks' revised regulatory proposal that may be worthy of further consideration by the AER. They include requesting the AER to revisit its PD in the following areas:

- The updated business case for additional 2-way monitoring in urban areas given the challenges of increasing PV (as per recent AEMO forecast), battery storage and embedded generation, and taking into account smart meter rollouts.
- The proposal for additional monitoring on selected High Voltage (HV) substations in rural and remote areas, given the potential for improving responsiveness to outages and fires;
- The business case for installing additional reclosers on powerlines in high bushfire risk areas (HBRA) as this will enable SA Power Networks to more effectively apply its statutory powers to disconnect electricity supply on high risk days;
- Increase the allowance for the Bordertown micro-grid project, subject to it being included as a DMIS project rather than a standard control service (SCS);
- Consider SA Power Network's proposed real unit labour costs for 2015-16 to 2017-18 in the light of Tribunal decision in 2010, providing there is an offset in labour productivity;

- Consider the allocation of labour costs between labour and contract labour in the PD using up to date information from SA Power Networks and other NSPs;
- Assess the business case for moving from a ten to a five-year asset inspection cycle in high bushfire risk regions of the state, providing that costs are efficient and an appropriate transition plan is in place.

To be clear, CCP2 is not making the above list as strong recommendations to the AER. However, these are areas of SA Power Networks' revised regulatory proposal where it has made a case for changes to the AER's PD. In addition, we remain committed to the view that the AER's principal task is to determine an overall capex and opex allowance. Therefore, the suggestions above should be considered in the light of their impact on the overall capex and opex outcomes in the AER's Final Determination (FD).

The following Table 2.2 provides a summary of CCP2's recommendations to the AER for consideration in its FD. The recommendations are also included in the relevant sections of this submission along with the supporting analyses.

Table 2.2: Summary of Recommendations

Category	Report Section	Recommendation for the AER's FD
Rules & Principles	3.1	The AER set out in the FD how it proposes to balance the factors it must have regard to in judging a proposal against the expenditure objectives and expenditure criteria set out in the NER. The AER seek further clarification from the AEMC on how a NSPs CE research is to be weighed against all the other factors in the rules and against evidence of consumers' views provided outside the CE research to the AER and others.
	3.2	CCP2 supports the AER's interpretation that its role is to set the regulatory allowance according to the requirements in the relevant jurisdictional and national laws and regulations; it is not the role of the AER to set explicit or implicit standards.
	3.2	The AER clarify the relationship between the SRMTMP and the economic expenditure objectives and criteria set out in the NER.
	3.3	CCP2 supports the AER's focus on the overall expenditure allowances; the AER's role is not to approve individual projects although it may take then into account as part of assessing the overall expenditure allowances.
	3.4	CCP2 supports the AER's policy position that it is up to SA Power Networks Board and management to decide how it will allocate its opex and capex allowances, taking into account the various incentive mechanisms and compliance requirements.
	3.5	CCP2 supports the AER's view that it does not approve (per se) expenditure allowances for SA Power Networks to undertake projects that are the main responsibility of other parties.
	3.6	CCP2 strongly supports the AER's position to not (per se) accept pass through of additional capex and opex for projects that improve efficiency and reduce costs for SA Power Networks. The policy, however, needs to be accompanied by a strong incentive regime and regulatory stability for both capex and opex incentives so that SA Power Networks has some confidence that in proceeding with an efficiency project it will retain benefits across regulatory periods.
	3.7	The AER take into account that the regulatory regime for a monopoly service seeks to replicate competitive market pressures. The AER's

		decisions can be usefully "stress tested" against the "competitive market benchmark.
Revenue & prices	4.2	The AER not accept SA Power Networks revised revenue proposal or revised price path for 2016-20 RCP. SA Power Networks has not adequately justified its revenue proposal as being in the long term interests of consumers. Consumers and their representatives have indicated strong opposition to SA Power Networks' revised revenue and price path.
Capex General	5.1.	The AER ensure that SA Power Networks capex efficiency does not decline over the next regulatory period. Overall capex should be set at a level that reflects changes in demand, previous levels of capex and is consistent with the expenditure objectives and criteria
	5.1	The AER take into account the increase in spare capacity in SA Power Networks' distribution system following the increases in capex during the 2010-15 RCP and the current levels of satisfactory compliance with the regulatory standards.
	5.2	The AER further examine the proposed capex to ensure that there is no double counting of capex between expenditure categories. CCP2 considers it is quite possible that, replacement capex addresses safety and reliability issues identified in augmentation capex (and vice versa).
Replacement Capex	5.3.2	The AER clarify whether there has been a mistake in its calculation of replacement expenditure. If there is a mistake, CCP2 recommends that the AER consider where other savings can be made. An allowance of over $700 million ($2015) is 85 per cent greater than in actual replacement opex in 2010-15. It is also excessive when compared to the level of augex and increases in spare capacity that has occurred over the 2010-15 RCP.
	5.3.2	The AER investigate the concerns expressed by a number of regional and remote area councils that the AER's PD did not allow sufficient funds to address their supply requirements. This might include discussions with ESCoSA on whether the reliability standards for electricity supply to regional, rural and remote areas provide sufficient incentives for SA Power Networks to adequately prioritise service to these areas, and particularly the LRDFs.
Augmentation Capex - General	5.4.2	The AER revisit the capex allowance for forecast demand growth and capacity constraints to ensure that its allowance is consistent with the growing spare capacity on the network and the extent of SA Power Networks' investment in upstream assets in 2010-15. SA electricity users should not be funding additional capacity that will not be utilised.
	5.4.2	The AER further investigate the options available for improved monitoring of the condition of the network, particularly in the light of AEMO's 2015 NEFR report regarding growing PV penetration and the minimum demand challenges identified by AEMO. The AER consider the benefits of improved monitoring on HV regional and rural substations that do not have access to SCADA given the concerns with reliability in some regions.
Safety augex	5.4.3	The AER does not accept SA Power Network's revised proposal for safety augmentation capex in its FD. This includes safety expenditure on additional bushfire mitigation and the undergrounding of the network in high-risk areas.
	5.4.3	The AER reconsider the merits of SA Power Networks' revised proposal for $18 million capex for remote controlled reclosers in regional areas as this will assist SA Power Networks' more effectively use its statutory powers to cut off electricity supply in periods of very high fire danger.
	5.4.3	The AER discuss with the SA Government the value of including an objective outcome measure such as the Victorian "F-factor" to supplement STPIS, given consumers concerns with bushfire risks.

	5.4.3	The AER provide more detailed benchmark information on the comparative costs of undergrounding across different DSNPs, and costs of alternative technologies to address exposure high bushfire risk areas.
	5.4.3	The AER investigate SA Power Network's proposal to extend its underground network by 14 per cent, while not extending its overhead network, particularly as the cost of undergrounding is so much greater and adds significantly to the RAB.
Reliability Augex	5.4.4	The AER discuss with ESCoSA whether it is expecting SA Power Networks to maintain, or in the alternative, improve the performance of the distribution network during MEDs. If this is the case, then ESCoSA's new standards might be made more explicit.
	5.4.4	The AER, in conjunction with ESCoSA, consider ways in which performance during MEDs can be appropriately included in any incentive scheme, if it agrees that MEDs performance is an important measure of network performance.
	5.4.4	The AER not accept SA Power Networks' proposed additional capex on low reliability distribution feeders (LRDF). There is no evidence that current expenditure allowances have been insufficient to progressively address LRDFs or have led to a sustained decline in performance; nor has there been a directive from ESCoSA to improve performance.
	5.4.4	The AER and SA Power Networks decide whether the Micro-grid Trial Program is better funded through the DMIS, which will have the added benefit of greater transparency and industry learning from the trial.
Strategic Augex	5.4.5	The AER provide a full assessment of the total life-cycle costs of the second cable to Kangaroo Island, including any expansion of the Kingscote substation and additional on-island back-up generation in the event that only the new cable supplies the island.
	5.4.5	The AER and SA Power Networks consider the option to include the KI cable as a contingent project under NER clause 6.6A.1(b) and 6.6A.1(c)(5).
	5.4.5	The AER not accept SA Power Networks' proposal to nominate a failure of the KI cable as a "pass through" event.
	5.4.5	The AER conduct an examination of the basis for SA Power Networks' costing of its network control plan in the revised regulatory proposal. The costs seem to have increased despite SA Power Networks' claim that there has been a reduction in the overall scope of the project.
	5.4.5	The AER not accept SA Power Networks' proposal for additional funds for network monitoring. SA Power Network's already has an ongoing program of rolling out SCADA and the costs of continuing this roll-out should be captured in its previous expenditures.
Non-Network Capex	5.5.2	The AER review the risks and timing of SA Power Networks' revised IT plan to ensure that it is prudent, efficient and deliverable, including the additional labour and contractor costs.
	5.5.2	In its FD, the AER consider whether the potential savings in opex that should arise in this RCP with the replacement of SA Power Networks' basic CIS and CRM IT are adequately captured in the opex allowance.
	5.5.2	The AER review its assumption that recurrent IT capex is allowed if it is consistent with 2010-15 recurrent capex. Recurrent capex should decline as a result of the update of key systems and business processes.
	5.5.2	The AER consider opportunities for savings in IT capex given SA Power Networks corporate links to two Victorian DNSPs. If it does, then CCP2 requests that the AER consider how these savings might be taken into account in its determination.
	5.5.3	The AER clarify if the proposed new CIS and CRM systems will have built-in capability to manage new tariff designs, larger data sets and competition in metering, thus avoiding high costs post 2017.
	5.6	The AER retain its forecast of escalation of input costs for capex.

OPEX	6.2	The AER not accept the overall opex proposed by SA Power Networks in its revised proposal. The AER's base year allowance may be too high, but the AER's decision on rate of change and step changes is in large part a satisfactory reflection of the Forecast Expenditure Assessment Guideline.
Opex base year	6.3	The AER re-examine its assumption that the actual costs in 2013-14 reflect efficient costs for the purposes of forecasting future costs, particularly given the decline in productivity observed over 2006 -13.
	6.3.2	The AER investigate and explain in its FD why SA Power Networks' Corporate and other cost category has grown so significantly since 2010, before it accepts 2013-14 as an efficient base year.
Opex rate of change	6.4.2.1	The AER not accept SA Power Networks' proposed increased opex as a result of the increase in capacity (specifically the use of growth in transformer and substation capacity) rather than ratcheted maximum demand).
	6.4.2.2	The AER review the approach it has adopted for 2015-16 and 2016-17 labour costs, taking into account decisions by the Tribunal. However, also consider the impact of SA Power Networks alternative inflation forecast that changes the real price increase in labour costs and reasonable expectations for labour productivity growth to reduce unit labour costs.
	6.4.2.2	The AER retain its approach, using Deloittes Access Economics (DAE) forecasts of EGWWS wages price index for 2017-18 to 2019-20
	6.4.2.2	The AER continue to assess contract labour costs as CPI, but it would be preferable to have these costs separately identified given the extent of contracting services now used by the DNSPs.
	6.4.2.2	The AER review its assumptions regarding the split between labour and non-labour categories, taking into account the more recent information from SA Power Networks and other DNSPs.
	6.4.2.3	The AER reconsider its forecast of zero per cent growth in the opex productivity factor, particularly given productivity growth in related industries (electricity transmission and gas distribution) and productivity gains in the wider economy.
Opex step changes	6.5.2	The AER reject the overall number and quantum of the proposed step changes in SA Power Networks' revised regulatory changes. The majority of the proposed steps do not reflect additional requirements and are captured in the base year or output growth. The step changes should also be considered in the light of the increases in most opex categories between 2006-13, which suggests that the base year 2013-14 would be higher than the average for the 2010-2015 RCP.
	6.5.3.1	The AER not accept SA Power Networks' revised proposal for additional funding for asset inspections as 2013-14 already includes enhanced inspection rates and there are no additional regulatory requirements.
	6.5.3.1	The AER reconsider the merits of the proposed increase in asset inspection cycles from 10 years to 5 years in HBRAs as there is a general change in industry practice to higher asset inspection rates in these circumstances. SA Power Networks should be required to demonstrate an efficient transition process and efficient inspection costs.
	6.5.3.1	The AER not accept the proposed step change for increased WHS obligations. The adoption of the national regulations in SA involves minimal change and the legislation allows for a transition period. The claim that SA Power Networks has not complied is concerning but not sufficient reason for higher opex allowance.
	6.5.3.1	The AER not accept proposed step change for RIN reporting. The 2013-14 base year should include sufficient funds given it was an establishment year and the updated IT systems should further enhance opex efficiency. Given SA Power Networks' claim that it has used estimated data for RIN reporting to date, the AER should further assess the accuracy of the

		historical benchmark studies, base year costing and capex planning.
	6.5.3.1	The AER not accept step changes for the introduction of demand based network tariffs as this is business choice by SA Power Networks to introduce this type of tariff (versus for example a time of use network tariff) and to do so before the regulatory requirement and in advance of a new CIS and CRM system.
	6.5.3.1	The AER only consider additional costs for competition in metering rule change when rule requirements and timing are clearer. If costs are sufficient, SA Power Networks can apply for a pass through of costs.
Opex & capital program impacts	6.5.3.2	The AER not accept SA Power Networks' proposed step change associated with expansion of its capex program, particularly as this expansion will (if prudent and efficient) lead to savings for SA Power Networks and electricity consumers would be paying twice. There are a number of projects in this category, however, that CCP2 requests the AER re-examine.
	6.5.3.2	The AER further investigate the business case for a new outsourced data centre. The case has some merit from a security point of view but it must be clear how savings will flow through to consumers in the future.
	6.5.3.2	The AER reconsider its position on a step change for enhanced information security. With increasing 2-way flows, there is greater risk of security breaches. There is also more general requirement for service providers to protect the privacy of customer information. However, the AER needs to ensure that SA Power Networks' proposal is efficient, particularly given the opportunities to build in additional security as part of the replacement of the CIS and CRM systems.
	6.5.3.2	The AER reject the proposed step change for SAP hardware upgrade costs. This project appears to be a standard part of business processes and it is likely to be equivalent expenditures in the base year (2013-14) that offset any increased costs of the new systems.
	6.5.3.2	The AER reject the proposed step change for additional opex following the changes to the CIS and CRM systems. Establishment and initial training and business redesign costs are usually capitalised. SA Power Networks is also avoiding the high costs of maintaining aging systems. A step change is not warranted given net costs and savings.
	6.5.3.2	The AER revisit its previous acceptance of a step change opex associated with shift of provider for mobile radio and communications. SA Power Networks' revised proposal includes an increase in cost and negotiations appear to be ongoing with consequent delays to the project.
	6.5.3.2	The Bordertown non-network solution raises more general issues on the question of recovery of increased costs associated with a project that is approved via a RIT-D. The AER to make clear on what basis can a DNSP get recovery for rising contract costs that have formed part of an accepted RIT-D project.
	6.5.3.2	The AER reject SA Power Networks' revised proposal for data quality enhancement. This assessment of data quality should be a standard process and consumers should not have to fund rectification costs.
	6.5.3.3	The AER reject a step change for enhancing customer service and safety information. These should be standard business practice and captured in the base year opex. In addition, consumers have access to considerable sources of information already (not just from SA Power Networks) and it is important to manage responsibilities for communication at key times.
Opex & vegetation management	6.5.3.3	The AER reject a step change for enhancing customer service and safety information. These should be standard business practice and captured in the base year opex. In addition, consumers already have access to considerable range and sources of information already (not just from SA Power Networks) and it is important to manage a consistent and centralised system of customer advice during emergencies

3 High level rules and principles for capex and opex assessments

As a prelude to examining the detail of the AER's PD and SA Power Networks' revised capex and opex proposals, it is useful to identify a number of high-level principles and common themes that are relevant to the task of economic regulation within an incentive based regulatory framework.

It is these principles that are central to the understanding the difference between the AER's PD and the initial and revised proposals from SA Power Networks. The same rules and principles underpin this current advice paper to the AER.

These principles must also be seen in the context of the 2012 reforms to the NER that placed a greater emphasis on the overall national electricity objective (NEO) and on the regulator setting a total capex and total opex allowance that best achieves the overall expenditure objectives as set out in the NER. The 2013 rule changes also clarified the interpretation of the expenditure objectives and are important to the CCP2's views on the capex and opex allowances.

The following sections set out the relevant rule changes and principles. They reinforce, and should be read in conjunction with, the AER's Expenditure Forecast Assessment Guideline.

3.1 The legal framework: A hierarchy of expenditure objectives, expenditure criteria and factors for the AER to have regard to

SA Power Networks places much emphasis in its proposal on the outcomes of its customer engagement (CE) process. However, it is a very big step to move from the outcomes of the CE research in general, and the willingness to pay (WTP) research in particular, to proposing many hundreds of millions of dollars of additional expenditure over and above the strict regulatory and operational requirements.

CCP2 has extensively discussed the merits and limitations of SA Power Networks' CE research in our previous submission to the AER. Further considerations by CCP2 are included at various points in this advice to the AER.

In this section, however, CCP2's focus is on understanding the requirements in the rules and how they relate to the AER's obligations in setting the expenditure allowances for capex and opex.

For example, in its revised regulatory proposal, SA Power Networks has made frequent reference to rules 6.5.6(e)(5A) and 6.5.7 (e)(5A) in the NER. These two new rules were inserted into the NER in 2012 as part of the overall reform of the NER designed to ensure the AER's decisions were in the long-term interests of consumers as required by the National Electricity Objective (NEO).

The two amendments cited by SA Power Networks state that in considering the capex and the opex proposals, the AER must have regard to: [6]

> *the extent to which the* [opex][capex*] forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course if its engagement with electricity consumers*

SA Power Networks claims that these two new rules mean that the AER must have regard to the wishes of electricity consumers as expressed in its CE research program. SA Power Networks then claims that the AER has given sufficient weight to its not had CE research.

CCP2 considers that SA Power Networks has somewhat overstated the AER's obligations under the rules and an alternative interpretation is set out below:

- The rules establish a hierarchy of matters that impact on the AER's decision whether to accept or reject an expenditure proposal;
- In terms of expenditure allowances, the responsibilities flow from the "expenditure objectives" to the "expenditure criteria" and then to the "expenditure factors";
- The expenditure forecast is required to meet the expenditure objectives;
    - o The AEMC has gone someway to clarifying the intent of the four expenditure objectives in its 2013 revision to the rules (see below). It makes clear that the regulatory task is to assess the efficient and prudent costs of meeting demand and complying with the regulatory requirements. And no more.
- The forecast must reasonably satisfy each of the three expenditure criteria; if it does not, the AER must not accept the forecast. The expenditure criteria include:
    - o The efficient cost of achieving the expenditure objectives;
    - o The costs that a prudent operator would require to achieve the expenditure objectives; and
    - o A realistic expectation of the demand forecast and cost inputs required to achieve the expenditure objectives.
- In deciding where it is satisfied or not, the AER must have regard to the expenditure factors;
    - o There are 11 expenditure factors set out in the NER.[7]
    - o These factors include the expenditure forecast to address concerns of electricity consumers (which SA Power Network relies on). However, the factors that the AER must have regard to also include the NSP's actual expenditure, the latest benchmarking reports, consistency with incentive schemes, and provision for non-network alternatives and other matters.
    - o A number of these factors are potentially in conflict. In having regard to each of the factors the AER must use its discretion to balance the factors in

[6] NEL, 6.5.6 (e) (5A) and 6.5.7(e)(5A)

[7] NEL, 6.5.6 (e) (4) – (12); 6.5.7 (e) (4)-(12).

order to best achieve the expenditure objectives and be satisfied with each of the expenditure criteria.

The AER's task is therefore not a simple as just relying on the CE research to assess whether the criteria are satisfied. It must not only assess the credibility of the research, it must put the NSPs CE research in the context of other sources of customer information and as only one part in the consideration of all 11 factors.

However, CCP2 does consider that the rules lack clarity around how CE research conducted by a network service provider (NSP) should be assessed in the context of an expenditure proposal, particularly for proposals that include additional funds beyond those required to meet the statutory obligations.

In particular, the following are two sources of potentially conflicting requirements:

- Through submissions and other means, the AER receives considerable feedback from consumers and their representative organisations. In SA, for instance, there were multiple submissions from representative organisations objecting to SA Power Network's additional expenditures and criticising aspects of the CE program.

- Similarly, the SA Government noted the feedback it has received from consumers and concluded that: "the results [of the CE research] do not align with the concerns expressed by South Australian electricity consumers at large"[8]. CCP2 experienced a similar inconsistency between SA Power Networks CE research and the feedback we received from meetings with consumer representatives.

  It is not clear how the AER is to balance the feedback from these other parties, who generally strongly opposed the increases in the proposed capex and opex, with the findings reported by SA Power Networks from their own CE research.

- The AEMC's amendments to the NER in 2013 to clarify certain aspects of the expenditure objectives and criteria. For example, the AEMC stated as part of the 2013 rule change that the capex and opex allowances:[9]

  > *The purpose of the rule change request is to clarify that operating and capital expenditure allowances for NSPs* ***should be no more than the level considered necessary to comply with the relevant regulatory obligation or requirement, where these have been set by the body allocated that role***.[emphasis added]

The 2013 changes to the NER are discussed in the following Section 3.2.

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[8] Government of South Australia, "Submission to the Australian Energy Regulator on the SA Power Networks' Regulatory Proposal 2015-2020", January 2015, p 12.

[9] AEMC, 2013, *Network Service Provider Expenditure Objectives, Rule Determination,* 19 September 2013, Sydney, p 30.

Notwithstanding the issues raised above, the CE research does provide a useful and less controversial contribution to SA Power Networks in assessing its priorities for expenditures within its regulated revenue cap.

Recommendations:

The AER set out in the FD how it proposes to balance the expenditure factors it must have regard to in judging a proposal against the expenditure objectives and expenditure criteria set out in the NER.

The AER seek further clarification from the AEMC on how a NSPs CE research is to be weighed against all the other factors in the rules and against evidence of consumers' views provided outside the CE research to the AER and others.

3.2 The AEMC's clarification of the NER requirements in its 2013 rule changes

3.2.1 The nature and intent of the 2013 rule changes

The AEMC's amendments to the NER in 2013 are highly relevant to the assessment of the AER's PD and SA Power Networks' revised proposal. These amendments sought to clarify a number of ambiguities in the AEMC's 2012 rule amendments relating to the determination of the opex and capex allowances.

In particular, a number of stakeholders expressed their concern that the four expenditure objectives set out in section 6.5.6 (a) and 6.5.7 (a) of the 2012 NER (applying to opex and capex respectively) did not make clear how the AER was to make its determinations when there had been changes to the reliability standards set by the jurisdictions.

This was because the original wording of the 2012 rule changes specified that the expenditure objectives directed the businesses and the regulator to assess expenditures on the basis of <u>maintaining</u> the reliability, security, quality and safety of the network. It was not clear how the AER would interpret "maintaining…" if a jurisdiction modified its reliability standards (as in NSW).

In September 2013, the AEMC made a rule determination that clarified the four opex and capex expenditure objectives. In summary, the 2013 amendments to the expenditure objectives state that the total forecast opex and capex must achieve the following:[10]

1. <u>Meet or manage</u> the expected demand for the SCS
2. <u>Comply</u> with <u>all applicable regulatory obligations or requirements for SCS</u>;

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[10] Summarised from NER 6.4.6 (a)(1) – (4) and 6.4.7 (a)(1)-(4).

3. If there is no applicable regulatory obligations or requirements in relation to quality, reliability or security of supply; to the relevant extent, maintain the quality, reliability and security of supply; and
4. Maintain the safety of the distribution system through the supply of SCS.

In other words, the regulatory task is to set total opex and total capex for SCS so as to satisfy electricity demand, comply with applicable regulatory obligations and maintain the safety of the distribution system. The expenditure objectives do not seek to go beyond these requirements; it is clear that the regulator's task is to determine expenditures for the 'must haves' not the 'nice to haves'.

In its final position paper, the AEMC also sought to address some related concerns that were raised by a number of the distribution NSPs (DNSPs, e.g. CitiPower and Powercor). These concerns centred on the view that the AEMC's amendments to the NER may have the effect of imposing a constraint on NSPs seeking to recover the costs of new innovative programs through the regulatory determination process.

The AEMC's response to these concerns in the 2013 rule review is of considerable relevance to assessing the AER's PD and SA Power Networks' revised regulatory proposal. For this reason, the AEMC's explanation in its final position paper is quoted at some length, as follows: [11]

> *The CitiPower/Powercor submission raised a concern about the intention to constrain standards, and therefore expenditure levels, to historical standards. The purpose of the rule change request is to clarify that operating and capital expenditure allowances for NSPs* ***should be no more than the level considered necessary to comply with the relevant regulatory obligation*** *or requirement, where* ***these have been set by the body allocated to that role****.* ***Expenditure by NSPs to achieve standards above these levels should be unnecessary, as they are only required to deliver to the standards set****. It would also amount to the AER substituting a regulatory obligation or requirement with its own views on the appropriate level of reliability, which* ***would undermine the role of the standard setting body, and create uncertainty and duplication of roles****.*
>
> ***NSPs are still free to make incremental improvements over and above*** *the regulatory requirements* ***at their own discretion****. Such additional* ***expenditure will not generally be recoverabl****e, through forecast capital and operating expenditure. However****, DSNPs are also provided with annual financial incentives*** *to improve reliability performance under the STPIS.* [emphasis added]

In addition to the concerns raised by CitiPower/Powercor and others, the NSW DNSPs queried why objective (4) had not been amended in the same way as the other

[11] AEMC, 2013, *Network Service Provider Expenditure Objectives, Rule Determination,* 19 September 2013, Sydney, pp 30-31.

objectives. Objective (4) still requires the NSP to "maintain the safety of the distribution system…".

In support of their concerns, the NSW DNSPs noted that in-house investigations into faults and failures, and external inquiries such as a royal commissions or coroners' reports, might lead a NSP to review its own activities even though there was no change in the regulations that it faced in its own jurisdiction.

In turn, this may lead a NSP to change its own business practices. For example, following the Victorian Bushfire Royal Commission (VBRC), a number of NSPs outside Victoria (including SA Power Networks) have proposed changes to their own procedures.

The NSW DNSPs proceeded to argue that it was unclear under 2013 rules whether the AER would consider that a NSP who undertook such actions (ahead of any regulatory requirement in their own jurisdiction) would be considered to be improving the safety of the network or was "maintaining" the safety of the network by bringing it up to a standard of safety which could reasonably be expected by consumers and the community more generally".[12] If the former, it seemed unlikely that they would get recovery of costs from the AER under the 2013 rules; if the latter, then perhaps they would get recovery through their regulatory allowances.

The AEMC was concerned with the complexity of making the NER more explicit with respect to safety because of the different bodies (national, jurisdictional, local) that may make rulings on safety issues. Therefore, the AEMC explicitly retained the initial wording in the NEL (rules 6.5.6(d) and 6.5.7(d)) regarding maintaining the safety of the network. The AEMC stated:[13]

> *In relation to the specific concern about safety raised by the NSW NSPs the Commission accepts that this* [the uncertainty of the AER's approach] *is the practical outcome of its decision not to amend or clarify the expenditure objectives in relation to safety. However, the decision also avoids the risk of creating subsequent definitional problems, and is wholly within the Commissions' view that there is a* ***current lack of practical evidence of a problem in respect of safety****.* ***Moreover, it does not preclude changes to legislated safety standards and expenditure in line with this****.* [emphasis added]

The CCP2 is most supportive of the AEMC's approach and of the AER's interpretation of its responsibilities taking into account both the initial 2012 rule changes and the AEMC's clarification of the rules in 2013.

The AEMC's commentary set out above makes very clear that the AER's primary responsibility is to set an allowance that is no more than is required to prudently and

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[12] NSW DNSPs, "Response to the Draft Rule Determination – National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013", 8 August 2013, p 2.

[13] AEMC, 2013, *Network Service Provider Expenditure Objectives, Rule Determination,* 19 September 2013, Sydney, p 31.

efficiently meet the regulatory requirements set by the designated jurisdictional or national bodies. It is these bodies that are tasked with setting regulation on behalf of the community's interests, and not the AER's task (whether explicit or implicit). For the AER to do otherwise would be to promote duplication of roles and inefficient and inconsistent requirements on the NSPs, an outcome that is not in the NSPs' interests or in consumers' long term interests.[14]

> *A more efficient outcome should arise if the decision of the body that is responsible for setting standards is given effect to in the regulatory determination as this body has been designated as the body best placed to make the decision. This also means that* ***duplication of roles is avoided*** *which could promote administrative efficiency.*
>
> *… the benefits of providing clarity and consistency as to the required level of reliability, security, quality and safety which would lead to regulatory certainty … Additional certainty could promote productive and dynamic efficiency.*

The AEMC's explanations also illustrate the responsibilities of the NSPs in this process in the context of the regulatory incentive framework. That is, NSPs are free to make their own expenditure decisions including improvements in service above the regulatory standards. However, such expenditure would not necessarily, or by right, be recoverable through the AER"s regulatory determination.

The AEMC's comments also imply that if a NSP considers that the standards in its jurisdictions are too low (taking into account developments outside the jurisdiction), or the standards do not cover important elements of its interaction with its customers, the NSP could make recommendations for change with the relevant jurisdictional authorities. This recognises that it is these authorities that are accountable for setting the standards rather than the AER through its economic regulation powers.

Recommendation:

CCP2 supports the AER's interpretation that its role is to set the regulatory allowance according to the requirements in the relevant jurisdictional and national laws and regulations; it is not the role of the AER to set explicit or implicit standards.

3.2.2 The status of the SRMTMP as a legal requirement, binding the AER

An outstanding question in terms of SA Power Networks' legal obligations is the status of the Safety, Reliability, Maintenance and Technical Management Plan (SRMTMP). SA Power Networks has frequently stated in its proposals that the SRMTMP imposes a legal obligation on it to undertake certain expenditures and for the AER to include these requirements in its capex and opex assessments.

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[14] Ibid, p 12.

For instance, SA Power Networks states that it "is required under the conditions of its Distribution Licence and section 25 of the Electricity Act 1996 (SA) to comply with its ESCoSA approved SRMTMP"[15]. The Office of the Technical Regulator (OTR) also reviews the plan and monitors the compliance.

CCP2 investigated this issue as part of its response to SA Power Networks' original proposal. We identified that while SA Power Networks is obliged to comply with its SRMTMP, the obligations are very general and the specific targets are set by SA Power Networks itself.

As the CCP2 understands it, the approvals by the OTR and by ESCoSA are not based on approving the economic value of the planed activities, but on ensuring the plan meets at least certain minimum criteria. ESCoSA will not approve an SRMTMP if it is contrary to the regulations. If, however, SA Power Networks sets out actions in its SRMTMP that go beyond those necessary under the regulations, ESCoSA will not disapprove it as it is not the economic regulator. That is, in many ways the specific actions set out in the SRMTMP are at the discretion of SA Power Networks, particularly content that goes beyond delivering to the regulatory requirements.

We therefore recommend that the AER further investigate the relationships between the SRMTMP as put forward by SA Power Networks and the relevance of this for the assessment of the regulatory proposals on economic criteria.

Recommendation:

The AER clarify the relationship between the SRMTMP and the economic expenditure objectives and criteria set out in the NER.

3.3 AER approves total expenditures for capex and opex rather than individual projects

The AEMC's intent in the 2012 rule changes was that the AER would focus its attentions on the overall opex and capex rather than individual expenditure projects. This is in contrast to a bottom up forensic examination of each expenditure claim as might be typical of a 'rate case' approach to regulation.

In doing so, the new rules make clear that the AER must also consider whether the proposed opex and capex are efficient and prudent and best satisfy the expenditure objectives and criteria in the NER. The AER also needs to consider the overall impact of its decision on consumers' long-term interests as per the NEO, and provide at least a reasonable opportunity to recover at least the efficient costs of providing the network services and complying with a regulatory obligation or requirement or making a regulatory payment as set out in the National Electricity Law (NEL).[16]

[15] SA Power Networks, *Revised Regulatory Proposal*, *2015-20*, July 2015, p 68.

[16] Adapted from the Revenue and Pricing Principles (RPP) in the National Electricity Law (NEL), Schedule 7A(2).

All these requirements set out above are high-level judgements. This point was also been reinforced by the AEMC during the process of amending the NER in 2012. For example, the AEMC states:[17] [18]

> ***The level, rather than the specific contents****, of the approved expenditure allowances* [capex and opex] ***underpin the incentive properties*** *of the regulatory regime in the NEM. That is, once a level of expenditure is set, it is locked in for a period of time and* ***it is up to the NSP to carry out its functions as it sees fit****, subject to any service standards*. [emphasis added]

and:

> *The AER* ***assesses the total of the capex or opex forecast*** *and is* ***not required to consider individual projects****.* [emphasis added]

Recommendation:

CCP2 supports the AER's focus on the overall expenditure allowances; the AER's role is not to approve individual projects although it may take then into account as part of assessing the overall expenditure allowances.

3.4 A NSP's Board and management are accountable for how the AER's total capex and opex allowances are spent

The corollary of the AER focussing on the total capex and opex allowances is that a NSP's Board and management team have accountability for how the allowed funds are spent within the context of compliance with the statutory obligations and requirements.

That is, having had their overall capex and opex allowances determined by the AER, the Board and management of the regulated business must choose the expenditure priorities (including capex and opex) and be accountable for the consequences of those choices to their shareholders, regulators and customers.

For example, a NSP's Board and management might choose to spend more on augmenting the system than in updating and replacing the system (or vice versa). At the end of the day, they are accountable for this choice. If it exposes the network to more interruptions then consumers should be compensated through penalties under the incentive schemes and Guarantee Service Level (GSL) payments.

Similarly, the Board and management might choose to spend more than "allowed" on IT infrastructure in the expectation that there will be benefits in operating costs down the line. Subject to complying with the law, it is up to the NSP to weigh the alternatives

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[17] AEMC 2012, Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Final Position Paper, 29 November 2012, Sydney, p 93

[18] Ibid, p 113.

(just as their business customers have had to do) taking into account the benefits, costs and risks of different actions.

Certainly, as part of the regulatory process the AER will consider the business and project plans put forward by the NSPs in their proposals. However, the AER's purpose in reviewing the individual project plans is to inform itself of matters to consider when assessing the overall expenditure proposals and determining the overall expenditure allowances.

The AER will consider that some of the projects proposed by a NSP are prudent and efficient and satisfy the expenditure objectives and criteria. However, the AER will also see that some of the NSP's proposed projects are not efficient and prudent and do not satisfy the expenditure objectives and criteria. Therefore, these latter projects are not relevant to the AER's consideration of the overall allowances and revenue cap that the NSP requires to maintain the reliability, quality and safety of the network system and network services.

Whether the AER agrees or does not agree with a particular project, however, does not prevent an NSP proceeding with that project. It simply means that in the AER will decide whether an individual project is relevant (or not relevant to) to the AER's assessment the total capex and opex.

For example, because the AER has rejected a number of SA Power Networks' opex step changes, this does not mean that SA Power Networks is barred from implementing those projects. It may choose to do so and (for instance) have a lower profit because it sees the project as having some benefit in the longer term, or it may work hard to achieve efficiencies in some other area to ensure the net cost is the same.

It may also look to partner with other businesses to share the costs and risks and there are several instances where it would seem more appropriate for SA Power Networks to adopt such an approach in preference to the 'go it alone' expenditures.

Recommendation:

CCP2 supports the AER's policy position that it is up to SA Power Network's to decide how it will allocate its opex and capex allowances, taking into account the various incentive mechanisms and compliance requirements.

3.5 Electricity consumers should not fund all network improvements if other parties have responsibilities

A concerning aspect of SA Power Networks' proposal is that it is seeking funds from electricity consumers for projects that (if adopted) should, in reality, be the primary responsibility of some other party. This issue is similar to the discussion in Section 3. 2.

For example, in its original proposal SA Power Networks proposed some $77 million ($2015) for road safety actions (undergrounding powerlines in "black spots"). SA Power Networks variously pointed to its general obligations to maintain a safe network and to the support it received for the project from consumers in the CE program. *[Note: we acknowledge that SA Power Networks has withdrawn this particular project in its revised regulatory proposal but it does serve to illustrate the point of principle.]*

As the SA Government pointed out strongly in its submission on SA Power Networks' original proposal, the management of traffic black spots is the responsibility of the SA Department of Planning, Transport and Infrastructure (DPTI), not SA Power Networks. The SA Government stated that it is not the role of the AER or SA Power Networks to set policy on this matter. Or, as the AEMC might say, DPTI is the body allocated to the role of determining the management of traffic black spots.

This is also an example of how the inclusion of WTP (and other) research outcomes, as part of a proposal to increases expenditures, can be problematic. Consumers indicated they were willing to pay for such a project, but that does not mean that SA Power Networks can then unilaterally take responsibility for and fund the project. Nor does it mean that the AER can approve funds for such a project, absent a direction from the responsible bodies in Government.

Similarly, SA Power Networks is proposing significant increases in its expenditure on vegetation management above the jurisdictional regulatory requirements, citing support from consumers in its WTP research and support by local councils. However, it also appears that councils do not wish to assist in funding enhanced vegetation projects although shared funding is standard practice in SA.

SA Power Networks is also proposing additional expenditures in relation to assets located in high-risk bushfire areas. SA Power Networks again states this additional expenditure is supported by its consumer research and by the precedence established by the Victorian Bushfire Royal Commission recommendations for Victorian NSPs (and others). However, in Victoria, the specific detail and priorities in the program were subject to assessment by a multi-representative specialist taskforce, not a workshop of consumers, and was funded by the state government, local councils as well as the relevant Victorian DNSPs.

In contrast, SA Power Networks' proposal puts all costs on electricity consumers irrespective of whether they share in the benefit, and what other sources of funding might be available to assist in funding the project.

CCP2 recognises that one difficulty facing SA Power Networks in responding to consumers concerns is that there are common network tariffs for each consumer segment (except very large customers) across the state. This means that all consumers share the costs of any project to improve amenity in a specific area. The common network tariffs in SA means that localised and/or discretionary expenditures must be very carefully evaluated as the costs are borne by all consumers.

Recommendation:

CCP2 supports the AER's view that it does not approve (per se) expenditure allowances for SA Power Networks to undertake projects that are the main responsibility of other parties.

3.6 Expenditures that improve a NSP's efficiency are not, per se, costs that can be passed through to electricity consumers

In its PD, the AER has emphasised an important point of principle that should be reflected in the regulator's decisions in an incentive based regulatory regime.

SA Power Networks has proposed cost recovery (both opex and capex) for expenditures that are designed to improve the efficiency of its operations on the basis that these expenditures will result in cost savings in the future.

In responding to these proposals, the AER has made clear that it does not accept the proposition that consumers should pay more now so that SA Power Networks can benefit from cost savings in the future including future payments under the AER's efficiency benefit sharing scheme (EBSS)

CCP2 supports this approach and it is a sound regulatory principle to guide the AER's decision making.

We do not accept, for instance, the argument put by SA Power Networks that it should be allowed a specific recovery of costs for investment in efficiency initiatives because customers may benefit some time in the future. The AER must look at the overall picture of costs and benefits, including the interplay of the proposal with the incentive schemes, before a case can be made for the AER to specifically provide for cost recovery of investment in such projects.

Nor do we accept the argument put by SA Power Networks, that the network should receive recovery of investment costs because there is a time lag between investment and positive returns to the company. While regulatory periods are discrete in some senses, the process of rolling forward the asset base, the operation of the incentive schemes and the use of benchmarking and historical costs to forecast future costs all point to a regime that has continuity through time and across regulatory periods. As it should, given the investments are generally long-lived assets.

Other than expenditure required for compliance with new laws and regulations, the expectation is that an efficient and prudent NSP will normally invest where there is a positive net benefit and will not invest when there is a negative net benefit.

More specifically, for a regulated monopoly service, the general incentive to invest in efficiency is supplemented by the regulatory incentive mechanisms, such as the efficiency benefit sharing scheme (EBSS) and the capital expenditure sharing scheme (CESS). Similarly, actions that improve reliability and service quality can be rewarded through the Service Target Performance Incentive Scheme (STPIS) or through reduced penalties such as those imposed under the Guarantee Service Level payments (GSL).

This is not to say that SA Power Networks is stopped from investing in projects that lead to cost savings or reliability enhancements. To the contrary, SA Power Networks would be wise to invest in projects that improve its productivity and provide long-term savings in the costs of its operations. This is what successful and sustainable companies do all the time. The only question is one of cost recovery.

In adopting this stance on efficiency investments, the AER is beginning to impose the disciplines of a competitive market, albeit a market with a range of special protections not generally available to businesses.

As discussed in the next section, CCP2 considers this is an appropriate position for the AER to adopt. Applying the policy will, over time, improve the accountability of the NSPs for their expenditure priorities and decisions. Overall, we consider that the AER's approach is more aligned with the intentions of the AEMC in amending the NER.

Recommendation:

CCP2 strongly supports the AER's position to not (per se) accept pass through of additional capex and opex for projects that improve efficiency and reduce costs for SA Power Networks.

The policy, however, needs to be accompanied by a strong incentive regime and regulatory stability for both capex and opex incentives so that SA Power Networks has some confidence that in proceeding with an efficiency project it will retain benefits across regulatory periods.

3.7 Applying the "competitive market" test

A key aspect of incentive based regulation is the objective of replicating the economic and financing disciplines of the competitive market place.

One aspect of this is touched on section 3.4, that is, the Board and management are accountable to their owners, community, customers and regulators for the decisions they make regarding financing structures and expenditure priorities.

Another aspect is effective risk management. Boards and management are accountable for making decisions on the risks that they choose to take, including investment risk.

More specifically, a businesses operating in a competitive market would face many of the types of challenges and cost pressures that SA Power Networks has cited at various points in the proposals. For example, all businesses are confronted with managing changing regulation and customer preferences. All businesses face the challenge of improving their efficiency and of adapting and embracing new technology.

In a competitive market many of these costs, such as installing a major new IT system cannot be passed through to customers. Therefore a business operating in a competitive market is constantly balancing the need to respond to its changing customer preferences with quality services, process innovation and new technology with the costs of implementing these changes. At the end of the day, the business has to be reasonably confident that the project will deliver a positive return to its shareholders over the longer term given the price constraints and funding constraints set by the competitive markets.

This regulator's decisions should impose a similar discipline on the regulated networks. The regulated price, together with the incentive mechanisms, acts as a proxy for the constraint of a competitive market price. The extent to which each NSP can innovate, reduce costs and deliver better quality services within the price constraints and regulatory requirements will influence the returns to its shareholders. [19]

In the regulated 'market', however, there appears to be some reluctance to accept the reality of the incentive regime and management accountability. It is almost as if the NSPs (including SA Power Networks) look to the AER to take responsibility for approving or disapproving each individual project before they can proceed with them – or not. For example, assume the AER has been asked in a proposal to approve (or disapprove) a step change for a specific "community safety project", however, there has been no change in the law. It is up to the Board and management to evaluate this project in the context of its past experience and future strategy as a business operating in the SA community.

Throughout SA Power Networks' proposal there are many such instances. It concerns CCP2 that the AER may find itself caught up in debates about the value of specific projects when this is rightfully the responsibility of the Board and management of SA Power Networks. As the AEMC said, and we quoted above, the AER is not required to assess individual projects. The AER's task is to set the total opex and capex allowances to meet the expenditure objectives and criteria including all regulatory and legal requirements.

It is important that the AER is consistent in its application of the AEMC's express requirement. To do otherwise risks the AER implicitly moving from an incentive based regulatory approach to a 'rate case' approach that identifies specific costs/projects and determines which ones will be included or not in a regulatory revenue case.

For example, SA Power Networks could use its customer research to apply to the SA Government to amend the bushfire management regulations to require more frequent inspections in bushfire prone areas. The Government, representing the SA community at large, can decide if such regulatory amendments are the most appropriate response to community concerns or whether there are alternatives available.

The point here, however, is that as the AEMC so clearly stated, it is not for the AER to implicitly or explicitly 'amend' the standards and thereby effectively undermine the relevant jurisdictional authority.

Recommendation:

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[19] For instance, in a competitive market if quality declined, the business would loose market share and ultimately profit would decline; in a regulated market the STPIS and GSL payments perform the same 'disciplinary' function.

The AER take into account that the regulatory regime for a monopoly service seeks to replicate competitive market pressures. The AER's decisions can be usefully "stress tested" against the "competitive market benchmark.

4 Overall Revenue for SA Power Networks

4.1 The AER's PD and SA Power Networks' revised revenue proposal

In its PD, the AER's allowed revenue was some 32 per cent below SA Power Networks' initial proposed revenue. The main reasons for this lower revenue allowance were:

- Reduction in the allowed rate of return (32 per cent) relative to SA Power Networks proposal – the rate of return is discussed in CCP2's separate paper to the AER;
- Reduction in allowed operating expenditure (21 per cent) – the changes to the operating expenditure are discussed further in Section 6 of this submission;
- Reduction in the regulatory depreciation allowance (43 per cent); and
- Reduction in the tax allowance (including adjustment for imputation credits (gamma)) (54 per cent).

There was also a significant reduction in the AER's allowed capital expenditure compared to both the initial and revised proposals by SA Power Networks. The reduction in capital expenditure impacts on depreciation and on the return on capital over multiple regulatory control periods. CCP2 discusses the AER's PD and SA Power Networks' revised capital expenditure proposal in Section 5 of this submission.

Table 4.1 summarises the differences between SA Power Networks' **original revenue proposal** and the AER's PD in terms of the percentage change in the overall building blocks for the five-year regulatory period (2015-20).

Table 4.1 also sets out SA Power Networks' **revised revenue proposal** relative to the AER's PD. Although SA Power Networks' revised proposal featured some reductions in operating and capital expenditures and a small reduction in the rate of return, overall, the revised revenue proposal is still some 29 per cent greater than the AER's PD.

Table 4.1: Comparison of revenue allowance 2015-20 between AER and SA Power Networks' proposals ($ nominal)

	Original Proposal compared to AER PD (% above AER)	**Revised Proposal compared to AER PD (% above AER)**
Return on Capital	32	23
Operating Expenditure	21	12
Regulatory Depreciation	43	49
Net Tax Allowance	54	56
Annual Revenue	**32**	**29**

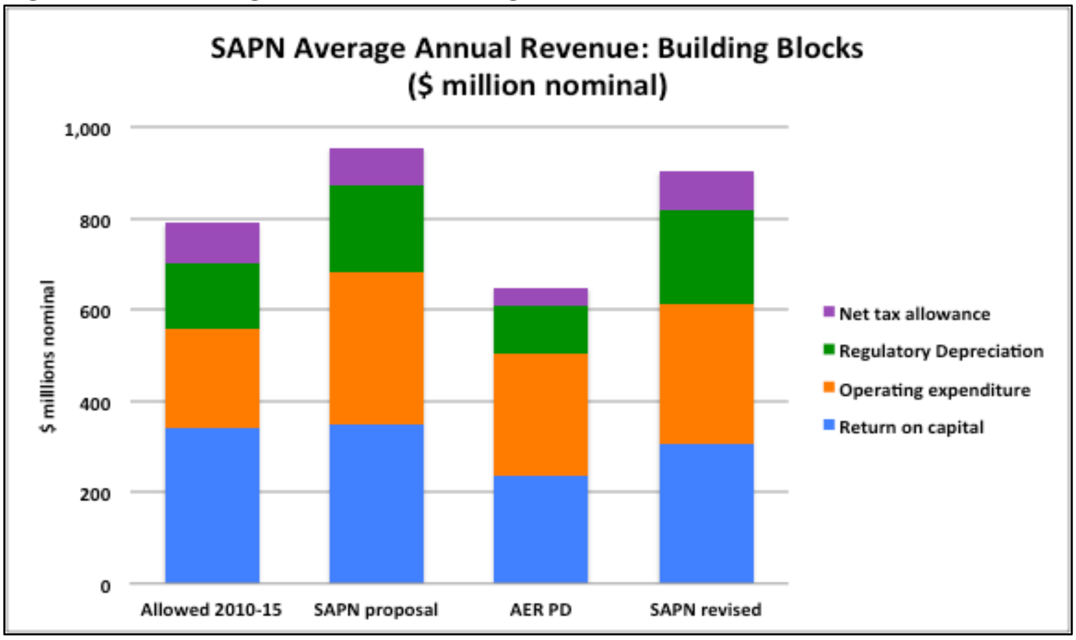
Source: SA Power Networks, *Revised Regulatory Proposal 2015-20,* (Tables 16.2 and 16.3); CCP2 analysis.

Figure 4.1 illustrates the differences between SA Power Networks' original and revised proposal, the AER's PD and the allowed revenue for 2010-15 RCP. SA Power Network's actual revenue was reasonably close to the allowed revenue in the 2010-15 RCP.

As Figure 4.1 demonstrates, the AER's revenue allowance for the 2015-20 RCP is less than the allowed revenue for 2010-15 RCP. The main driver for this reduction is the significant reduction in the return on capital reflecting much lower government and commercial bond rates.

The AER's depreciation allowance and net tax allowance are lower than SA Power Networks, and these also contribute to the overall lower revenue allowance.
In contrast, however, the AER's allowance for operating expenditures has increased somewhat compared to 2010-15.

Figure 4.1: Building Blocks and Average Annual Revenue ($ millions, nominal)



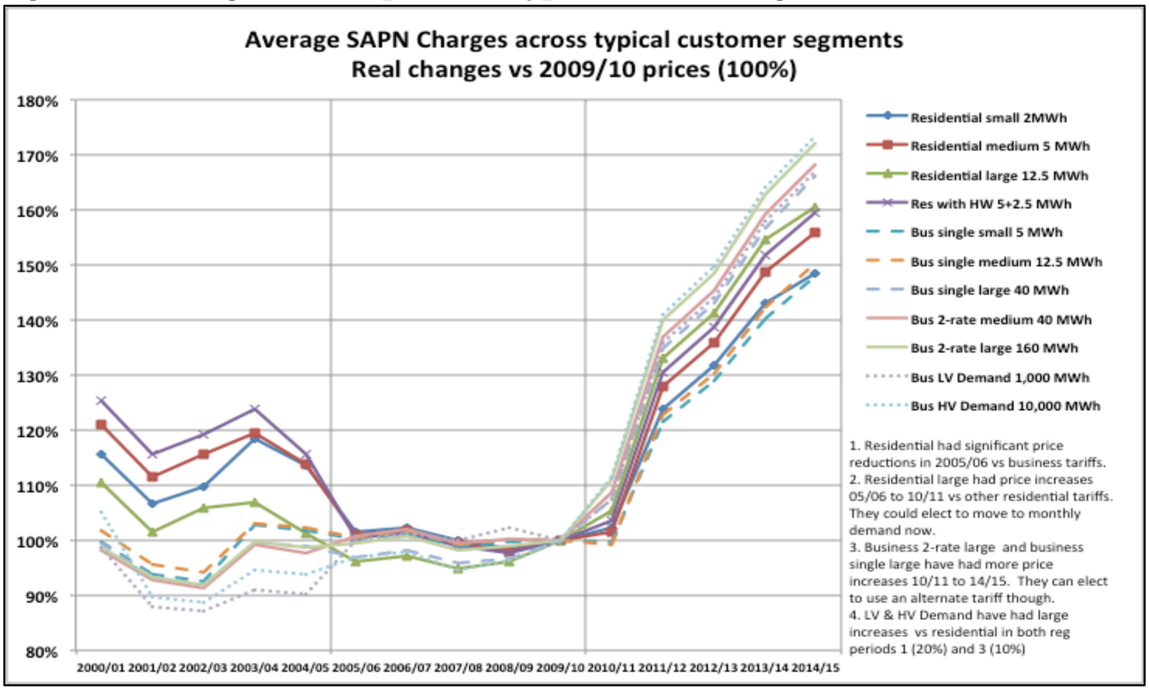
Source: SA Power Networks, *Revised Proposal, Regulatory Determination 2015-20*, July 2015, Tables 16.2 & 16.3; CCP2 Analysis.
Note: Chart does not include other adjustments to revenue such as incentive scheme payments.

The different revenue outcomes have a significant impact on the network prices that SA consumers will face in the next four years as discussed below in Section 4.2.

4.2 Impacts on SA electricity network prices 2016-20.

The 2010-15 RCP saw massive and unprecedented increases in average network charges as illustrated in Figure 4.2 below. The increases came on the back of a substantial increase in the cost of capital immediately following the GFC, and increases in operating and capital expenditure allowances in response to expected growth in demand and the need to replace older infrastructure.

Figure 4.2: Average network prices for typical customer segments 2000-01 to 2014-15



Source: SA Power Networks, History of network tariffs, Customer prices history tariff data model xlsx.

Against this background of network price increases on 2010-15, SA Power Networks' original regulatory proposal for 2015-20 would see a further increase of around $13.3 or (0.6 per cent) ($ nominal) per annum in the 2015-20 RCP. Similarly, business customers would have seen a continuation of the high prices of the previous years, with increases of around $25 ($ nominal) per annum over the 2015-20 regulatory period.[20]

SA Power Networks promoted this outcome as providing relief to SA electricity consumers from the increases in network prices that had previously occurred.

CCP2 strongly opposed the price outcome set out in SA Power Networks' original proposal. We argued that SA Power Networks' proposal would have "locked in" the huge increases in network prices between 2010 and 2015 and provided no relief to SA business and residential consumers.

SA Power Networks' original price proposal was also not commensurate with the dramatic drop in the cost of capital or the reduction in demand relative to previous forecasts. Moreover, the proposed increases in opex and capex were very substantial and not justified by the demand forecasts, the age of the network or historical reliability performance.

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[20] AER, *Preliminary Decision SA Power Networks distribution determination*, Attachment 1, p 1-16.

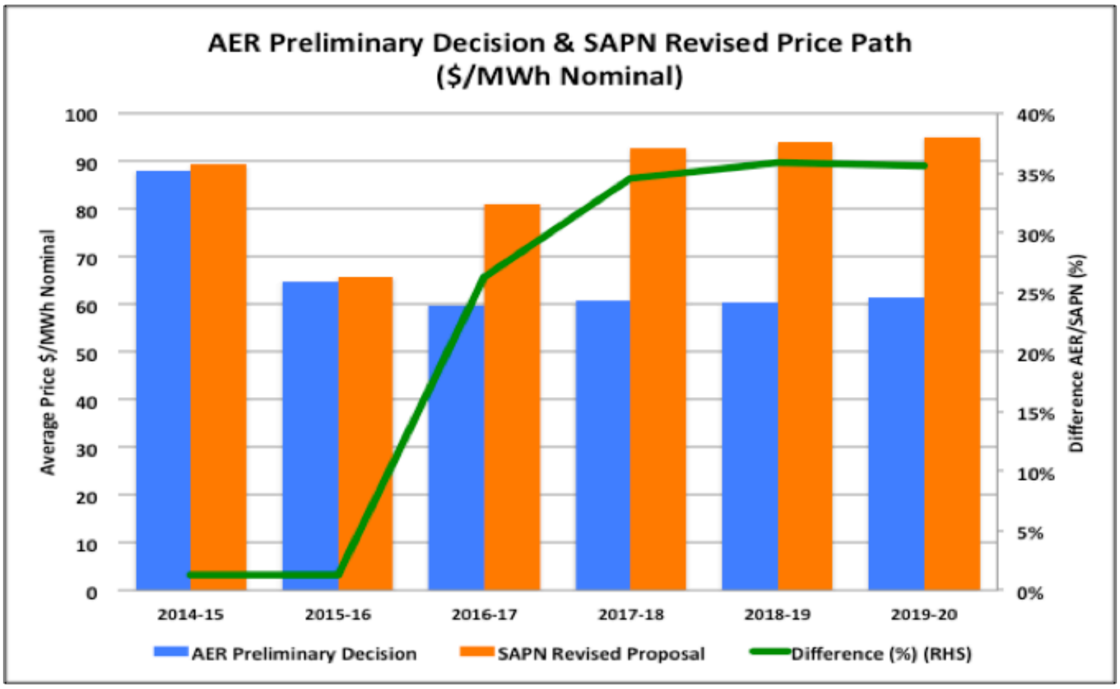
Equally concerning was the increases in the underlying cost structure of the business. , The increases in the underlying cost structure of the business, albeit disguised by the lower cost of capital, would create price pressures in the future when interest rates rose again. This was an unacceptable risk for SA electricity consumers.

In marked contrast, the AER's PD provides some significant price relief to SA consumers. The AER estimated that an average residential user in SA would (all other things being equal) see a reduction of some $197 (9.8 per cent) in 2015-16 and a further decrease of about $9 or (0.5 per cent)($ nominal) between 2016 - 20.[21]

Similarly, small business customers with an average usage of around 10,000 kWh per annum would see savings of around $381 in 2015-16 and further decreases of about $17 for the remaining regulatory period ($ nominal).

SA Power Networks' revised proposal, however, includes a dramatic change to the AER's PD price path. While the AER's 2015-16 price reductions are in place, SA Power Networks' revised proposal means that there is a "claw back" of these price reductions and a return to the era of high and sustained network prices. See Figure 4.3:

Figure 4.3: The impact of SA Power Networks' revised proposal on network prices 2016-2020



[21] Based on an average usage of around 5,000 kWh per customer for a residential customer. See AER, *Preliminary Decision SA Power Networks distribution determination*, Attachment 1, p 1-15.

Source: AER Revised Proposal PTRM ("revenue cap" nominal price path); SA Power Networks Revised Proposal ("revenue cap" nominal price path). The slight differences in 2014-15 and 2015-16 average prices reflect the impact of small changes in energy use for 2014-15 and 2015-16 under the revenue cap control mechanism. The 2015-16 average prices are based on published prices and reflect the AER's PD.

As illustrated in Figure 4.3, SA Power Networks' prices will be some 26 per cent higher than the AER's PD in 2016-17, and increasing to around 35 per cent higher in each of the remaining three years 2017-18 to 2019-20.

It is, therefore, not surprising that both household and business representative groups have provided submissions supporting the AER's PD and strongly opposing the network price increases set out in SA Power Networks' revised regulatory proposal. A review of the many submissions made on behalf of both individuals and representative groups reveals a number of consistent themes:

- SA Power Networks' price increases are not in the long term interests of customers;
- The proposed price increases follow on from very significant increases in the recent past;
- The price increases have not been justified by SA Power Networks;
- SA Power Networks' consumer engagement program is "flawed" and not a sound basis for proposing such large price increases;
- SA Power Networks' revised proposal builds in the prospect of continued price increases beyond 2020 because of the high capital spend; and
- The AER's PD may not have gone far enough to cut prices, but it is a significant improvement over SA Power Networks' regulatory proposal and is generally "strongly supported".

The submission from the Riverland Energy Association illustrates these common themes, as follows:[22]

> *We believe the* [AER's PD] *determination is fair and reasonable for both SA Power Networks and energy consumers. There is no justification for the proposed increases put forward by SA Power Networks in its Revised Regulatory Proposal 2015-20.*
>
> ***The unrealistic Capital and Operating expenditure put forward by SA Power Networks in its proposals demonstrates a lack of true understanding of its customer's views and expectations****. It in fact demonstrates that SA Power Networks own consultation process is flawed and did not present balanced information or data.* [Emphasis added]

In its revised proposal SA Power Networks is somewhat dismissive of the submissions from consumer representative groups to the AER. SA Power Networks emphasises the

[22] Riverland Energy Association, "Submission to SA Power Networks Regulatory Proposal (2015-2020)", 20 July 2015.

results of its own CE research as reason for discounting the numerous submissions that opposed the additional expenditures in both the original proposal and the revised proposal.

However, these submissions have come from well-informed and experienced organisations whose members have in some cases participated in SA Power Networks' CE program. These organisations also represent many individuals and organisations. The 17 stakeholders and stakeholder organisations that SA Power Networks cites in its revised proposal as making "comments, observations or assertions"[23], also represent many thousands of businesses and households in Australia and deal at the coal face with the impact of high electricity prices.

Their concerns should not, therefore, be so lightly dismissed. Indeed, there is an increasing tone of frustration in consumers' submissions to SA Power Networks' revised regulatory proposal. The submissions to SA Power Networks' revised regulatory proposal talk of SA Power Networks' showing an "inconsiderate approach to customers", a "cavalier approach to customers" and disappointment that the proposal "would not deliver these electricity price cuts to customers".[24]

Nevertheless, it is important to highlight that a number of SA councils have provided submissions in support of aspects of SA Power Networks' revised regulatory proposal. These submissions expressed concerns that the AER's PD will prevent or delay SA Power Networks' addressing network issues in their local areas. Further comments on the concerns of local councils' in regional and rural areas are addressed in the capex and opex sections of this advice paper.

The following Sections 5 and 6 will consider a number of the components of the AER's Preliminary Determination and SA Power Networks' revised regulatory proposal, namely capital expenditure and operating expenditure.

Recommendation:

The AER not accept SA Power Networks revised revenue proposal or revised price path for 2016-20 RCP.

SA Power Networks has not adequately justified its revenue proposal as being in the long term interests of consumers. Consumers and their representatives have indicated strong opposition to SA Power Networks' revised revenue and price path.

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[23] See SA Power Networks, Revised Regulatory Proposal, 2015-20, p 27.

[24] The quotations listed come from various submissions including inter alia Century Orchards, Jubilee Almonds Irrigation Trust Inc , Business SA. Other user submissions included similar expressions of disappointment with the revised proposal, and support for the AER's PD.

5 Capital Expenditure (capex)

5.1 Overview

The capex allowance impacts on the revenue building blocks in a number of ways. That is, SA Power Networks' capex increases its regulatory asset base (RAB), and the amounts allowed for the return on capital and the return of capital (depreciation). It may also drives increases in opex given claim that delivering on a 'larger' network will lead to higher operating costs.

Capex also has long-term impacts on network prices that go beyond the 2015-20 RCP because of the long life of the network assets. As a result, higher capex increases the risks facing consumers as a result of increases in government and commercial interest rates and declining electricity demand.

The AER is required to determine a capex allowance that is efficient and prudent and is necessary to meet forecast demand, comply with regulatory requirements and maintain a reliable, secure and safe network consistent with these regulatory requirements.[25] However, we also expect the AER to look very carefully at proposals that increase expenditure beyond that; such proposals require very strong evidence of the benefits to consumers of such investment.

Hence, CCP2's response to SA Power Networks' original and revised proposals includes two elements. First, we recognise SA Power Networks' current relative efficiency and prudency in the delivery of network infrastructure services and its history of compliance with the requirements of the regulatory regime in which it operates. Second, however, we are deeply concerned about SA Power Networks' proposed increases in capex for 2015-20 above historical levels of expenditure.

We consider that SA Power Networks' initial and revised proposals substantially increase capex and, therefore do not represent efficient expenditure. Nor is such a level of capex investment prudent given the challenges that SA Power Networks has outlined in its proposals, such as lower demand, poorer load factors and (we would add) increasing spare capacity on the network.

In the face of these challenges, a business would not normally expand its asset base and increase its underlying costs in the way proposed by SA Power Networks. Rather it would seek to preserve its capital and maximise the efficiency of its current service

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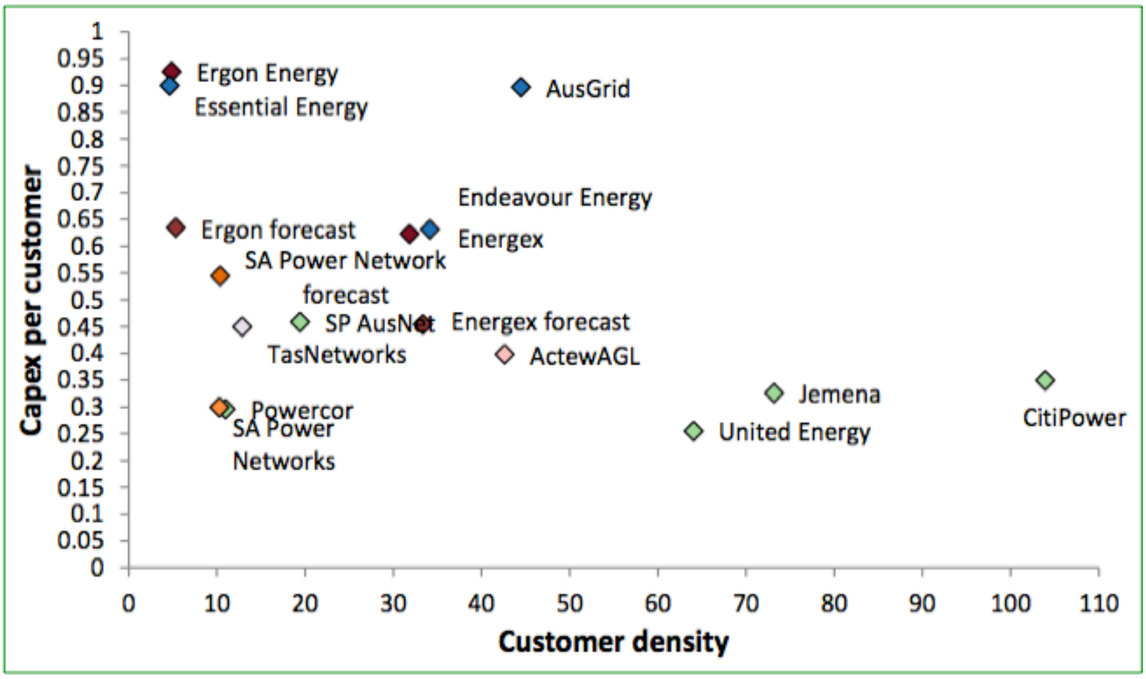
[25] We are definitely not suggesting that SA Power Networks should not strive for a higher service levels. It should as a matter of good business practice and because the incentive mechanisms potentially provide funds for that over time.

operations, an outcome we see today in non-regulated businesses facing the risks of declining demand and/or prices.[26]

Figure 5.1 illustrates the issue using a partial factor productivity (PFP) measure (capex per customer). If SA Power Networks' original capex forecast were accepted by the AER, then SA Power Networks' relative capex efficiency per customer would decline by a factor of almost 50 per cent.

Given SA Power Networks' frequent reference to its relative efficiency, it should be a matter of some concern to SA Power Networks that its efficiency will deteriorate to the extent indicated in Figure 5.1, as will its relative position compared to other DNSPs, as both Ergon and Energex DNSPs propose improvements in their capex efficiency.[27]

Figure 5.1: Capex per Customer by DNSP/Change in outcomes for SA and Qld DNSPs



Source: AER, *SA Power Networks, Preliminary Decision 2015-20*, Attachment 6, Capital Expenditure, Figure 6-4, p. 6-27.

As discussed in the following sections in more detail there is no reason in terms of demand growth, capacity constraints and current reliability, quality and safety for SA Power Networks to increase its capex over current levels.

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26 See for example, recent announcements by Santos: "First half capital expenditure was more than 50% below 2014 levels and unit production costs for the first half year were 11% lower". Santos ASX/Media Release, 17 August 2015.

27 The chart demonstrates the changes between current and forecast capex per customer scores for the three DNSPs; SA Power Networks, Energex and Ergon undergoing simultaneous reviews by the AER.

Many of these issues, such as capacity constraints and reliability changes were canvassed extensively in CCP2's response to SA Power Networks' proposal and we refer the AER to CCP2's previous submission as further evidence of the CCP2's for more details of the reasons for the CCP2's views.

Recommendations:

The AER ensure that SA Power Networks capex efficiency does not decline over the next regulatory period. Overall capex should be set at a level that reflects changes in demand, previous levels of capex and is consistent with the expenditure objectives and criteria.

The AER take into account the increase in spare capacity in SA Power Networks' distribution system following the increases in capex during the 2010-15 RCP and the current levels of satisfactory compliance with the regulatory standards.

5.2 Review of SA Power Networks' capex proposals

The AER's PD reduced SA Power Networks' original proposed capex by some 32 per cent over the 2015-20 RCP. The reductions in expenditure allowances covered all of the three main categories of capex, namely; replacement, augmentation and non-network capex. The AER has accepted SA Power Networks' fourth category of expenditure, the net connection capex (i.e. connection capex less customer contributions).

This paper does not comment on connection capex but it is expected that the AER will investigate the volume and cost of the connections set out in SA Power Networks' revised regulatory proposal.

Although SA Power Networks' revised capex proposal is less than its original proposal, it is still some 20 per cent above the AER's PD. Figure 5.2 illustrates the differences between SA Power Networks' two proposals and the AER's PD. It also compares these outcomes with SA Power Networks' actual capital expenditure in 2010-15. The chart disaggregates the overall capex into the four expenditure categories.

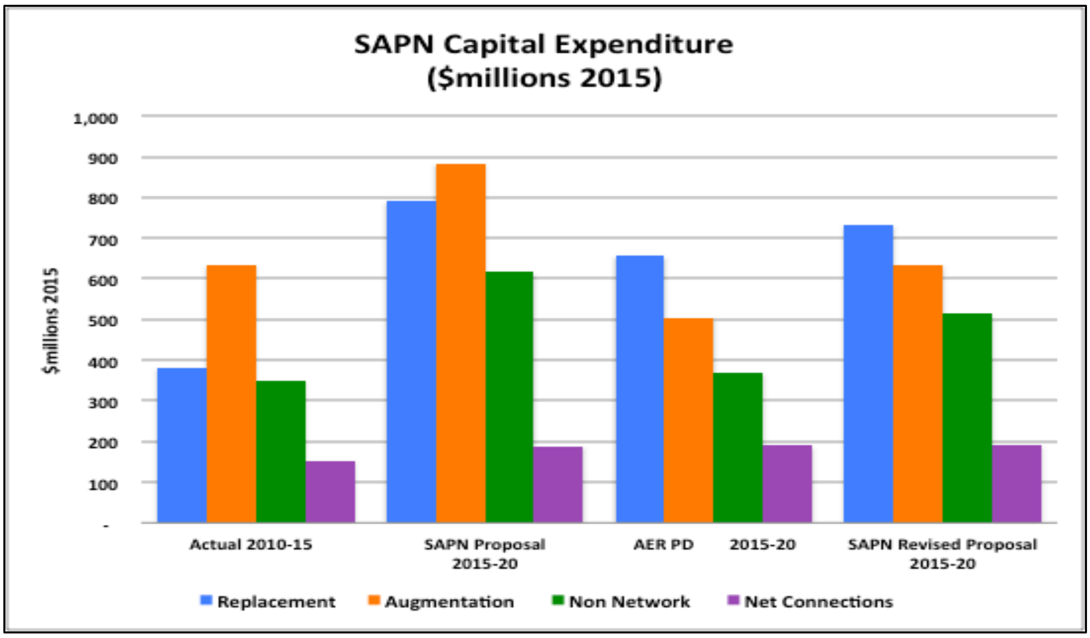
A number of the important changes in the proposed capex on each of the three main expenditure categories are discussed below.

It must be highlighted, however, that it is difficult to see in SA Power Networks' proposal where the line is between replacement and augmentation capex. It is a real concern that there is potential for 'double counting' of capex given the potential overlaps between the categories.

For example, what is the line between replacement capex and safety and reliability augmentation capex? While the AER provides some definition of these categories it does not address the double counting issue adequately. For example, replacement capex can also contribute to improving safety and reliability outcomes (and vice versa).

Indeed it would be somewhat concerning if SA Power Networks did not adopt a replacement capex plan that did not place a priority on reliability and safety outcomes. However, it is not clear if tasks undertaken under "reliability opex" are not also tasks undertaken as part of replacement capex.

Figure 5.2: SA Power Networks' actual and proposed capex and the AER's PD ($ million, 2015).



Source: SA Power Networks, *Revised regulatory proposal 2015-20*, July 2015, Table 7.1 & 7.4, AER PD April 2015, CCP2 analysis.

Recommendation:

The AER further examine the proposed capex to ensure that there is no double counting of capex between expenditure categories. CCP2 considers it is quite possible that, replacement capex addresses safety and reliability issues identified in augmentation capex (and vice versa).

5.3 Replacement Capex

5.3.1 Summary of AER's PD and SA Power Networks' revised proposal

SA Power Networks' original proposal for 2015-20 included a replacement capex of some $792 million ($2015),[28] more than double SA Power Networks' actual replacement

[28] SA Power Networks, *Revised Regulatory Proposal, 2015-20*, July 2015, Table 7.1, p 60. The numbers in the revised proposal differ from other reports. For consistency, we have used the numbers from SA Power Networks' published revised proposal as much as possible.

expenditure in 2010-15 RCP and over three times the AER's allowance for 2010-15 RCP. [29]

The main reason SA Power Networks gave for this massive increase in expenditure was a change in its approach to the assessment of network risks from an age based to condition based assessment. This change followed a more extensive investigation of the condition of its assets.

The AER's PD reduced SA Power Networks' replacement capex allowance by 17 per cent to $657 million ($2015).[30] However, this was still more than 70 per cent greater than SA Power Networks' actual replacement capex for 2010-15.

SA Power Networks' revised proposal of $732 million modifies some aspects of its original replacement capex proposal. However, the revised proposal still represents an increase of more than 90 per cent compared to SA Power Networks' actual replacement expenditure in 2010-15 and is around 11 per cent higher than the AER's PD allowance.

The AER considers that its allowance represents a significant increase over 2010-15 actual expenditure (in real dollars) and therefore provides SA Power Networks with sufficient resources to meet its regulatory requirements and maintain the safety and reliability of its network given the age profile of the network and other condition factors.

However, SA Power Networks states that the AER has made an error in its calculations of some $51 million. Correcting for this error explains a large component of the $70 million dollar difference between the AER's PD and SA Power Networks' revised replacement capex proposal.

5.3.2 Response to AER's PD and SA Power Networks' revised proposal

CCP2 assumes that the AER will investigate the "error" that SA Power Networks claims it has made and amend its assessment in the Final Determination if appropriate.

Overall the AER's PD of $657 million is very generous and provides ample scope for SA Power Networks to increase the rate of replacement of its older downstream assets (powerlines etc.).

The increased replacement funding is also sufficient to allow SA Power Networks to adopt a higher replacement/repair rates in specific areas of poor reliability or high bushfire risk which it has identified in its regulatory proposals.

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[29] Source: SA Power Networks, *Regulatory Proposal 2015-20*, November 2014 p 182. SA Power Networks overspent its regulatory replacement capex of $239 million ($2015) by around 60 per cent.

[30] Ibid, Table 7.4, p 64.

In particular, the fact that the AER has allowed replacement capex funding that is some 72 per cent more than SA Power Networks actually spent in 2010-2015, strongly suggests it does not need additional funds (over and above the approved amounts) for hardening the networks, addressing poor supply reliability areas and high bushfire areas.

SA Power Networks categorises these additional funding requirements as augmentation (see below). However, our point remains.

Whether poor reliability is addressed through capex classified as replacement capex or as part of augmentation capex is simply a matter of reporting convention. However, it does pose a significant risk of "double counting" expenditures as highlighted above. In any case, the underlying fact remains that there is an additional "bundle of money", over and above historical levels of replacement expenditure that is more than sufficient to address the additional network enhancement activities identified by SA Power Networks - if SA Power Networks wishes to prioritise them.

However, if SA Power Networks is correct, and the AER has made an error in its calculations (see above), then the AER's PD to allocate over $700 million ($2015) for replacement capex cannot be supported. This would amount to an allowance that was 85 per cent greater than SA Power Networks actual replacement capex in 2010-15 in $2015.

Recommendation:

The AER clarify whether there has been a mistake in its calculation of replacement expenditure. If there is a mistake, then the AER consider where other savings can be made. An allowance of over $700 million ($2015) is 85 per cent greater than in actual replacement opex in 2010-15. It is also excessive when compared to the level of augex and increases in spare capacity that has occurred over the 2010-15 RCP.

CCP2 notes here that a valuable use of SA Power Networks' extensive CE program is to assist SA Power Networks in setting priorities for its capex.

For example, SA Power Networks may have regarded reliability of supply to remote areas as a lower priority because of the limited number of customers affected by a loss of supply. However, SA Power Networks' customers have indicated that it is important for SA Power Networks to prioritise and address issues such as reliability in remote supply regions.

Evidence provided by the SA Minister for Mineral Resources and Energy in a submission to the AER also supports the contention that the AER's PD allowance is very generous. The Minister's submission highlights that capex related to replacement of older assets has: "already spanned multiple regulatory periods since 1999".[31] The submission goes on to state that: [32]

> *As such, it is reasonable to provide that* ***SA Power Networks should already be well underway in their ongoing asset replacement program*** *which has featured heavily in the previous 2 determinations and it is therefore concerning that the current Regulatory Proposal again seeks an increase of over 3 times the 2010-15 allowance.*
>
> *Furthermore, this capital expenditure proposal is directly linked to SA Power Networks' requirements under the Safety, Reliability, Maintenance and Technical Management Plan* [SRMTMP]. *It is therefore necessary for the AER to establish through engineering advice, how quickly defects need to be rectified and* ***whether the entire $792 million is necessary over the next 5 years to ensure a safe and reliable supply of electricity****.* [emphasis added]

In its revised proposal, SA Power Networks is still seeking a replacement capex allowance of some $732 million ($ 2015). Therefore, the Minister's comments on SA Power Networks' original proposal remain relevant to the AER's assessment of SA Power Networks' revised proposal.

Given this substantial increase in replacement expenditure, it is concerning to read the comments in a number of council submissions to the AER written in response to SA Power Networks' revised proposal. We do not understand why SA Power Networks would advise councils in writing that the AER's PD does not allow SA Power Networks' to address their basic supply issues when in fact there has been an increase in the overall capex allowance, particularly for replacement expenditure.

For example, the City of Marion states in its submission to the AER that it has written to SA Power Networks to express its concern about the lack of maintenance on the wooden cross arms on their local power lines. The submission also states that SA Power Networks replied (15 July 2015) that they would rectify "P1" defects but added the following caveat:[33]

> *With the current level of funding approved by the AER in its Preliminary Determination for the 2015-20 RCP, SA Power Networks is unlikely to rectify the remaining P2 and P3 defects until they become P1 defects some time in the future.*

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[31] Government of South Australia, "Submission to the Australian Energy Regulator on the SA Power Networks' Regulatory Proposal 2015-2020", January 2015, p 3.

[32] Ibid.

[33] City of Marion, "Submission to the AER re SA Power Networks – Determination 2015-20", July 2015. SA Power Networks records defects identified in asset inspections as category P1, P2, P3 and P4 on the basis of its maintenance risk value methodology. P1 defects are defects that pose a significant/likely risk to safety or interruption of supply and should be rectified within 28 days. P2 defects are classified as non urgent as no plant failure has occurred but there is potential to deteriorate/fail and should be rectified within 180 days. And so on.

We find this response by SA Power Networks to a council concerning on several levels. In particular, our understanding from SA Power Networks' original proposal is that the number of assets at P1 level of risk is relatively low, and is reasonably constant both historically and across the forecast period.[34]

Given the substantial increase in the AER's PD allowance for SA Power Networks' replacement capex, there seems no a priori reason why SA Power Networks should suggest it is only now (i.e., following the AER's PD) restricting its services to replacing P1 condition assets only, as seems to be implied by the letter from the City of Marion.[35]

We also note the concerns in submissions from some five rural and remote councils about the number of "low reliability distribution feeders"(LRDF) in their districts.[36]

ESCoSA monitors LRDF performance and the results are published in ESCoSA's "Annual Performance Report for SA Power Networks". A review of the most recent report suggests that there is no obvious pattern of improvement or decline in the overall number of feeders classified as LRDF between 2010-11 and 2013-14. The South East region is the only region where there has been an increasing trend for poorer service in LRDF across the 4 years.[37]

ESCoSA also states that in 2013-14, a total of 28 feeders were regarded as LRDF for more than two years, compared to 2012-13 when 31 feeders had been classified as LRDF for more than two years.[38]

In the most recent public report for 2013-14, ESCoSA demonstrates its pragmatic and realistic approach and concludes:[39]

> *Remediation of LRDFs is dependent, to a degree,* ***on the extent of the benefit gained relative to the cost of the work****. Understandably, there will be situations where the* ***costs far outweigh the benefits****. There will continue to be parts of the network with lower reliability; however, SA Power Networks should ensure that reliability in these areas* ***does not decline over time****. To some extent, GSL payments serve to balance the impact of poor performance for the poorest served customers.* [emphasis added]

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[34] See SA Power Networks, *Regulatory Proposal 2015-2020*, November 2014, Figures 20.9, 20.18 and 20.20, pp 184 , 191 and 195.

[35] More specifically, the AER has allowed some $52 million ($2015) for repex on pole top structures, which is consistent with previous regulatory period allowance.

[36] ESCoSA defines a low reliability feeder as a feeder that has exceeded 2.15 times the duration of interruption relative to the service standard within that region.

[37] ESCoSA, *Performance of SA Power Networks*, Report 2, 2013-14, Table 13, p 8. It is likely that this decline was affected by severe weather in this region.

[38] Ibid, Table 12, p 7.

[39] Ibid, p 7.

While ESCoSA is not suggesting that SA Power Networks is non-compliant with its regulatory obligations with respect to LRDF feeders there is a clear expectation that SA Power Networks would not allow the situation to deteriorate.

SA Power Networks has received 70% more replacement capex allowance in the 2015-20 period compared to its previous actual expenditure as noted above. This provides an opportunity for SA Power Networks to prioritise a number of these areas as part of its plan to address consumers concerns (while taking note of the relative costs and benefits).

Recommendations:

The AER investigate the concerns expressed by a number of regional and remote area councils that the AER's PD did not allow sufficient funds to address their supply requirements.

This might include discussions with ESCoSA on whether the reliability standards for electricity supply to regional, rural and remote areas provide sufficient incentives for SA Power Networks to adequately prioritise service to these areas, and particularly the LRDFs.

5.4 Augmentation capex[40]

5.4.1 Summary of AER's PD and SA Power Networks' revised proposal

Augmentation capex normally refers to capex designed to support growth in average demand and demand arising from new customer connections. However, it may also include actions taken to improve safety, reliability and environmental outcomes as well as strategic investments.

SA Power Networks' initial proposal included a total of $884 million ($2015) in this category of expenditure, largely as a result of increased capex proposed for safety, reliability and strategic projects.[41] This amount is nearly 40 per cent more than SA Power Networks' actual augmentation expenditure in 2010-15.

The AER's PD reduced the allowance to $505 million ($2015), largely because the AER did not accept SA Power Networks' proposals for significant additional expenditures in safety, reliability and strategic projects.

SA Power Networks' revised proposal increases this to $635 million (some 21 per cent above the AER's PD) mainly because it rejects the AER's PD in relation to safety, reliability and strategic augmentation capex projects.

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[40] The dollar figures referred to in this section 4.1.2 for the 2015-20 period are largely from SA Power Networks, *Revised Regulatory Proposal, 2015-20*, July 2015, Table 7.7, pp 70-71. The figures include overheads and differ from the numbers reported by the AER in its PD.
[41] SA Power Networks, *Revised Regulatory Proposal, 2015-20*, July 2015, Table 7.4, p 64.

The following sections consider each of the categories of augmentation expenditure and provide an assessment on the AER's PD and SA Power Networks' revised proposal.

It should be noted, however, that the categories of expenditure are not constraints on SA Power Networks' activities; it is the overall capex that is important rather than individual categories and SA Power Networks' can direct its total capex allowance as it sees appropriate, taking into account its regulatory obligations.[42]

5.4.2 Demand driven augmentation

The demand driven augmentation has two major components. They are:

- "Core program augmentation" (as defined by SA Power Networks – largely equivalent to the AER's "Forecast demand growth and capacity constraints –see note below); and
- Quality of supply augmentation projects.

Note: For consistency, the figures quoted below are taken from SA Power Networks' revised regulatory proposal and are somewhat different than the figures quoted in the AER's Preliminary Determination as also noted by SA Power Networks in the revised regulatory proposal. SA Power Networks' figures include allocation of overheads and balancing items (see notes to Table 7.7, p 70).

5.4.2.1. The AER's PD and SA Power Networks' revised proposal

SA Power Networks' original regulatory proposal included $345 million for demand driven augmentation, an amount that is considerably less than the amount allowed in the 2010-15 RCP determination and also less than the amount SA Power Networks actual spent ($436 million $ nominal).

The AER's PD allowed $325 million ($2015) in total for demand driven augmentation. SA Power Networks' revised proposal ($326 million) is largely consistent with the AER's PD.

Based on SA Power Networks' analysis, the AER has allowed a total of $270 million ($2015) for "core programs" (including forecast demand growth and capacity constraints) and $55 million ($ 2015) to address quality of supply issues.[43] SA Power Networks' revised regulatory proposal includes the same split between the two categories.

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[42] For example, CCP2 has previously commented that SA Power Networks' increase in repex and decrease in augex in 2010-15 relative to the AER's allowance was a sensible adjustment to changing market conditions. Under the CESS, there will be no penalty for under spending or overspending on individual elements of the DNSP's plan.

[43] See SA Power Networks, *Revised Regulatory Proposal 2015-20*, Table 7.7, p 70. The AER has stated that SA Power Networks original proposal included $186 million ($2014-15) for localised demand growth and existing constraints.

Given the declining peak demand in the 2010-15 RCP and the forecast of flat peak demand growth over the 2015-20 RCP, the AER's PD is based on expected capex required to meet demand growth in localised areas (such as new estates) and to address a number of identified substation capacity constraints given forecast growth in those areas.

5.4.2.2. A response to AER's PD and SA Power Networks' revised proposal for demand driven augmentation

- **Demand driven augmentation – core investments.**

The AER's PD allowance for the core demand driven capex is overly generous in the current circumstances. Factors that are relevant of further consideration by the AER in its FD include the following:

- SA Power Networks plans to expand the implementation of demand tariffs for the residential and small business tariff market commencing in 2015-16 ahead of the AEMC implementation dates. If SA Power Networks proceeds with that plan, demand tariffs are likely to reduce average peak demand towards the end of the 2015-20 regulatory period.[44] Alternatively, a well-designed time-of-use tariff will achieve a similar outcome;
- Penetration of solar PV in new estates ("pockets of growth") is likely to be higher than average and this will have some effect on growth capex requirements. Similarly, houses in new estates can be expected to be more energy efficient than the average housing stock.[45] To the extent that the pockets of growth are in middle to high density developments in the Adelaide city and fringe area it can be expected that average usage per customer (which is already trending down)[46] will be lower;
- Spare capacity in the network is growing and zone substation utilisation declining. Even if there are new pockets of demand growth, it is less clear how this translates into expansion of the network at the distribution and zone substation level. SA Power Networks provides some data on this, however, CCP2 would expect to see close examination of these claims given the past expenditure (see below).
- SA Power Networks has already invested heavily in the renewal/expansion of distribution and zone sub-stations and transformers in 2010-15 with expansion of

[44] Currently, the number of customers on this tariff is limited, as it requires a type 1-4 meter or type 5 monthly read meter. Some residential solar customers are on a Type 4 meter for instance. See http://www.sapowernetworks.com.au/public/download.jsp?id=50898

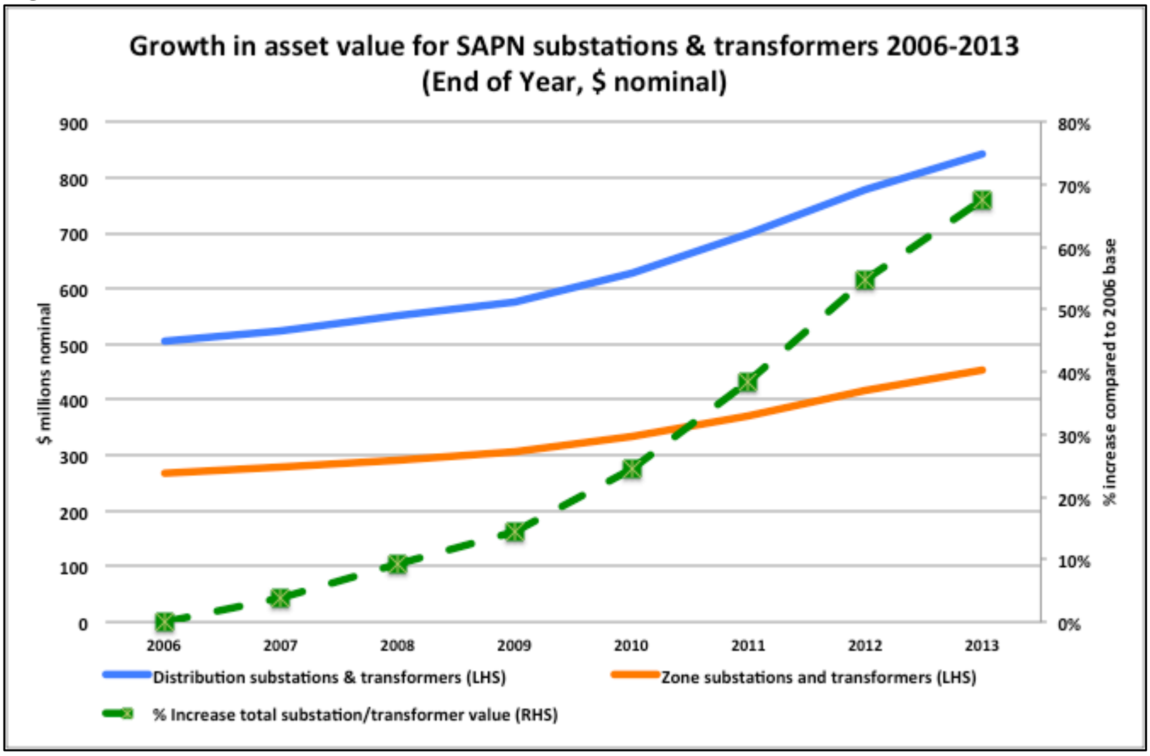
[45] For example, SA Power Networks forecasts that over the next 15 years, for new premises: 80% will have solar PV (versus 60% for existing homes); 80% of new premises will have an energy management system (50% existing homes) and 25% have energy storage (20% existing homes). See SA Power Networks, *Future Operating Model, 2013-2028*, p 11. [Attachment 7.7 to original proposal]

[46] See AEMO, *2015 National Electricity Forecasting Report, Detailed Summary of 2015 Electricity Forecasts*, June 2015, Figure 31, p 56.

the value of the substation/transformer asset base by nearly 70 per cent between 2006 and 2013 (see Figure 5.3).

- It is unlikely that a repeat of this level of expenditure is required in 2015-20. Therefore, although SA Power Networks makes a reasonable case for some of the specific substation expansions/replacements, there should still be a reduction in expenditure requirements relative to the 2010-15 regulatory period.

Figure 5.3: Growth in Substation/Transformer Asset Values 2006-2013 (cumulative)



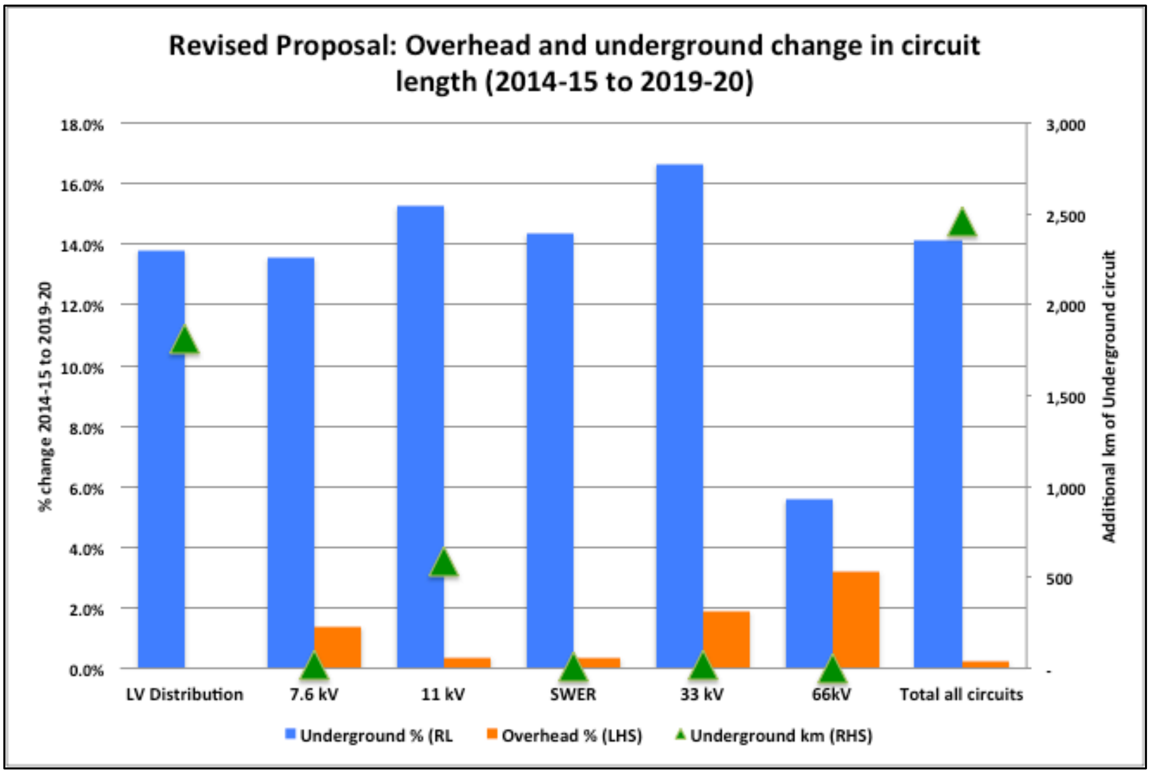
Source: SA Power Networks Economic Benchmarking Consolidated Information 2006-2013 (4. Assets). CCP2 analysis. Note: The % increase in value is relative to the 2006 base year.

For these reasons, it would appear that the AER has adopted an overly conservative position on demand growth related augmentation expenditure and one that does not adequately reflect the current increases in spare capacity and the previous investment in the upstream assets (distribution and zone substations and transformers). Given the spare capacity and uncertain forecasts for future demand, there is a real risk of continuing the trend towards overinvestment in network capacity.

There is also little evidence to support the contention that the physical asset base is expanding to any noticeable degree (although the economic value of the asset base is clearly doing so), despite SA Power Networks' claims about pockets of growth in new estates.

Figure 5.4 highlights that SA Power Networks forecasts little change in overhead circuit line length across the 2015-20 RCP, although there is some growth in the forecast of underground power line assets. The same report suggests that there is virtually no growth in system capacity (MVA) for each of the kV segments over the forecast period 2015-20.

Figure 5.4: SA Power Networks proposed physical asset growth 2015-20



Source: SA Power Networks, Revised Reset RIN, Tables 3.5.1.1 & 3.5.1.2; CCP2 analysis. Note: there is only 183 km of overhead circuit line length growth from 2014-15 to 2019-20.

The forecast of a capacity constraint of the Aldinga substation also appears to be problematic even though the AER has approved the substation replacements. For instance, is the most appropriate response to construct a new substation at Maslin Beach on the basis of "contingent capacity" rather than normal available capacity as this substation?[47] Table 5.1 below from the AER's PD highlights this concern.

Recommendation

The AER revisit the capex allowance for forecast demand growth and capacity constraints to ensure that its allowance is consistent with the growing spare capacity on the network and the extent of SA Power Networks' investment in upstream assets in 2010-15. SA electricity users should not be funding additional capacity that will not be utilised.

[47] This is based on AER, *SA Power Networks, Preliminary Decision*, April 2015, Table B-3 and associated discussion on p 6-44.

Table 5.1: Utilisation of sample of zone substations to be augmented

Table B-3 Utilisation of sample of zone substations to be augmented

Substation	2014/15	2015/16	2016/17	2017/18	2018/19
Clare	0.79	0.79	0.80	0.80	0.80
Campbelltown	0.80	0.81	0.82	0.83	0.85
Aldinga	0.51	0.54	0.56	0.58	0.61

Source: AER, *SA Power Networks Preliminary Decision 2015-20,* April 2015, Table B-3, p 6-44.

Demand driven augmentation - quality of supply & two-way networks

In addition to the core growth related capex, SA Power Networks sought an additional amount of $76 million for managing quality of supply ($55 million) and two-way networks ($21 million).

While the the AER appears to have adopted a conservative position on general growth capex, the AER's PD correctly includes a reduction in SA Power Networks' proposal for quality of supply expenditure by some 27 per cent.

The AER's PD includes an allowance of $55 million. The AER has specifically rejected the need for an additional investment of $19.6 million ($2015) in network monitoring in line with SA Power Networks' forecast of doubling of solar PV installations by 2020.

In support of this reduction, the AER states that it does not accept SA Power Networks' forecast growth in PV. The AER adopted a lower growth rate in solar PV installations and stated that it believes SA Power Networks can manage this lower growth rate using its current approaches to managing quality of supply as these have worked to date.

However, in its PD, the AER also stated that it would review the forecast of PV following the publication by AEMO of the National Electricity Forecasting Report 2015 (NEFR 2015).

SA Power Networks has accepted the AER's PD in its revised proposal. However, SA Power Networks does propose an additional $2.6 million ($2015) to install high voltage two-way monitoring in rural areas that do not have SCADA control during the 2015-20 RCP. [48]

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[48] CCP2 notes that SA Power Networks regards this program as being for RIN compliance.

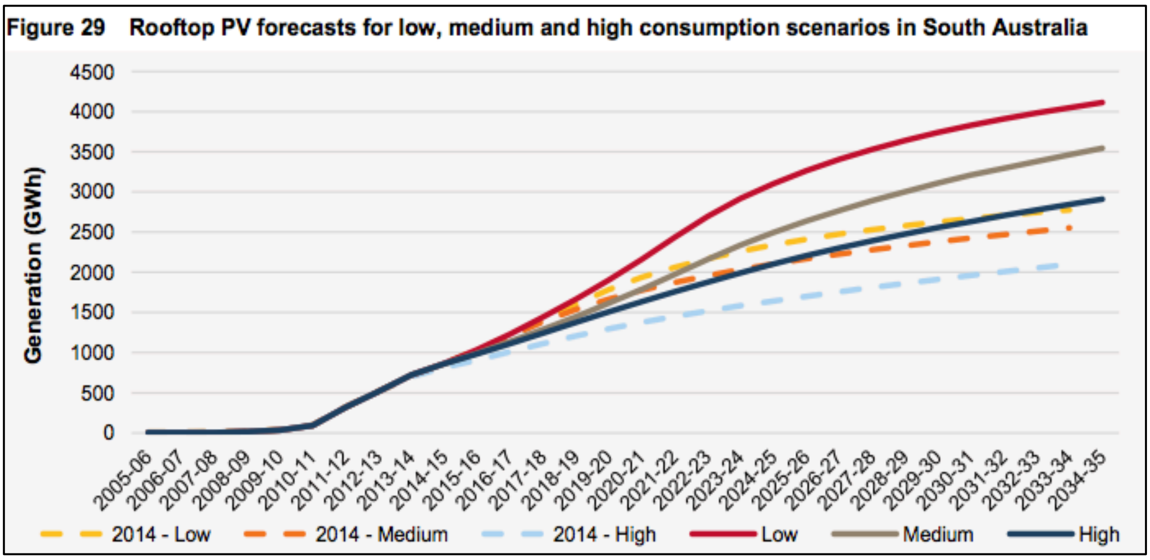
Response to the AER's PD and SA Power Networks revised proposal

SA Power Networks appears to have been able to manage the quality of supply issues to date, despite the challenge of rapidly growing solar PV penetration as the AER has stated (above).

The question therefore concerns the rate of growth in solar PV in the RCP and the optimal method for managing that growth. The NEFR (2015) indicates that AEMO has increased its overall demand forecast and increased its forecast of solar penetration compared to NEFR (2014).

Figure 5.5 illustrates the change in forecast of PV generation, particularly after 2020 between the 2014 NEFR and the 2015 NEFR. Figure 5.5 also demonstrates a growing range of uncertainty around the forecasts of PV.

Figure 5.5: AEMO 2015 NEFR Forecast



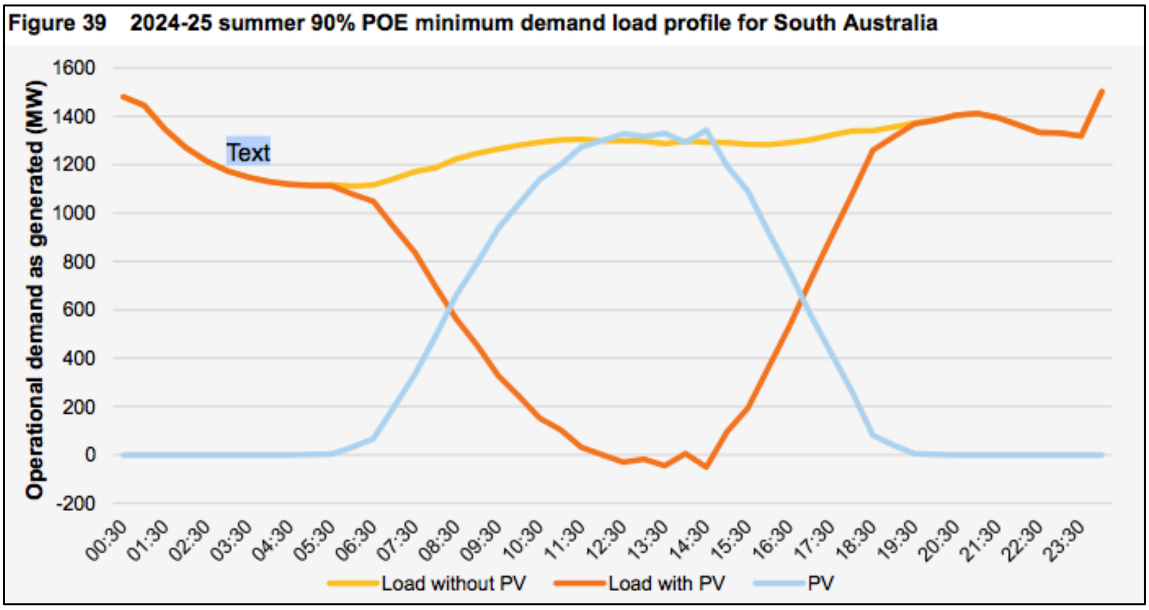
Source: AEMO, *2015 National Electricity Forecasting Report*, June 2015, Figure 29, p 53.

Figure 5.6 demonstrates an emerging issue of the minimum demand, as rooftop solar displaces more and more generation in the middle hours of the day.[49] To the extent this happens, there may be additional complications for SA Power Networks' in managing the quality of supply on the network in real time.

Given the issues facing SA Power Networks, the question of maintaining the stability of the network is likely to become increasingly important over the 2015-20 RCP.

[49] See AEMO, *2015 National Electricity Forecasting Report, Detailed Summary of 2015 Electricity Forecasts*, June 2015, Figure 31, pp 60-65.

Figure 5.6: Summer 90% POE Minimum Demand Load Profile Forecast for SA



Source: AEMO, *2015 National Electricity Forecasting Report*, June 2015, Figure 39, p 63.

We cannot comment on the most cost effective way to manage these developments, and whether investment in two-way monitoring is the most appropriate approach. For instance the progressive roll-out of smart meters will provide useful and objective real time information on number and location of quality of supply issues on the network.

However, overall it does suggest that additional resources to assist SA Power Networks in the management of the quality of supply will be required over the course of the RCP.

The proposal to install additional monitoring on the HV sections of the network in regional and rural areas also has merit although the AER might consider this type of project as an extension of normal business.

Recommendations:

The AER further investigate the options available for improved monitoring of the condition of the network, particularly in the light of AEMO's 2015 NEFR report regarding growing PV penetration and the minimum demand challenges identified by AEMO.

The AER consider the benefits of improved monitoring on HV regional and rural substations that do not have access to SCADA given the concerns with reliability in some regions.

5.4.3 Safety augmentation capex

5.4.3.1. The AER's PD and SA Power Networks' revised proposal

SA Power Networks proposed to spend $321 million ($2015) on safety capex in the period 2015-20. This is almost a twenty-fold increase in expenditure compared to the 2010-15 period ($17 million, $ nominal[50]). The additional $300 million dollars since 2010-2015 can be attributed to two programs, a bushfire mitigation and protection program ($222 million ($2015)) and a road safety program ($78 million ($2015)).

The AER PD severely cut back SA Power Networks' proposed safety augmentation capex. The AER's PD approved a total of $22 million ($2015), with this amount being much in line with previous "core" expenditure on safety. The AER made no additional allowance (above current expenditure) for bushfire mitigation and safety programs.

The AER concluded that additional expenditure was not required to maintain the reliability and safety of the network. There had been no significant change in relevant regulations and/or safety standards, there was no evidence of increasing risk of powerlines igniting fires and there was no/inadequate cost benefit assessment of the programs submitted by SA Power Networks.

The AER was not convinced that the CE research findings provided sufficient support for these programs in the absence of an objective cost-benefit analysis or historical necessity.[51]

SA Power Networks' revised safety capex proposal is $108 million ($2015). SA Power Networks has removed the road safety program from its revised proposal, and has reduced its proposed bushfire program expenditure by around $135 million. SA Power Networks, however, considered, that the AER had not paid sufficient heed to its CE research findings.

5.4.3.2. Response to safety augmentation capex

Much of SA Power Networks' proposal for additional safety augmentation capex relative to 2010-15 was justified on the basis of its CE research. SA Power Networks suggested that the CE studies revealed that consumers placed a priority on safety and were willing to pay more in their electricity bills for improvements to reduce the risks of powerlines starting bushfires and powerlines that created road safety risks.

These "safety" augmentation claims by SA Power Networks raise a number of the principles that were discussed in Section 3 of this paper. The following sections provide a more detailed examination of these issues.

5.4.3.3. Safety and bushfire risk management

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[50] SA Power Networks, *Regulatory Proposal 2015-20*, April 2015, Table 20.33, p 224.

[51] AER, *SA Power Networks, Preliminary Decision*, April 2015, Attachment 6, p 6-50.

In addition to the CE research, SA Power Networks also referred to the recommendations of the Victorian Bushfire Royal Commission (VBRC). SA Power Networks suggested that that the VBRC recommendations regarding powerline safety redefined what was acceptable "industry best practice" in relation to managing the risk of electricity assets starting bushfires.

It seems, therefore, that SA Power Networks regards the VBRC recommendations in Victoria (made in response to the Victorian bushfires of 2009) as having created a new operational "standard." That is, SA Power Networks considers it has a responsibility to invest in its network to align with the VBRC recommendations and its assumption that the VBRC sets new standards for non-Victorian DNSPs.

Arguably, therefore, SA Power Networks' proposal assumes that the VBRC recommendations subsume the relevant legislation in SA that was prepared initially in response to the 1983 Ash Wednesday bushfires in SA.

Also implicit in SA Power Networks' original and revised proposal, is that the VBRC recommendations have been adopted in full in Victoria and funded only by electricity consumers over a short period of time.

Neither of these assumptions is correct as discussed below and in greater detail in the previous submission by CCP2 on SA Power Networks' original proposal.

To begin with, SA Power Networks' operational standards are defined by the legislation and regulations in South Australia, not Victoria. The SA Government introduced legislation initially in response to the Ash Wednesday bushfires in 1983 and updated over the following decades. However, there do not appear to be any equivalent or consequential changes to the SA legislative requirements that would lead to such substantial cost increases.

This is confirmed by the submission to the AER from the SA Minister for Mineral Resources and Energy. The two most relevant pieces of legislation identified by the SA Minister in the submission are: [52]

- The *Electricity Act 1996*, section 53: this empowers SA Power Networks to disconnect the distribution networks in extreme conditions to minimise the potential for catastrophic bushfire. The *Electricity Act 1996* also gives a head of power for the regulations; and
- *Electricity (Principles of Vegetation Clearance Regulations) 2010*: these Regulations prescribe vegetation clearance requirements around power lines.

The submission from the SA Minister for Minerals and Energy sets out the following relevant information:[53]

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[52] Government of South Australia, "Submission to the Australian Energy Regulator on the SA Networks' Regulatory Proposal 2015-20", 30 January 2015, p 5.
[53] Ibid.

> *In recognition that electricity infrastructure has the potential to ignite or contribute to bushfires, South Australian electricity legislation places obligations on SA Power Networks aimed at reducing bushfire risk as well as empowers it to take appropriate action where there is a risk of bushfire.*

These requirements have been in place for some time and there do not appear to be any significant incidences of non-compliance by SA Power Networks. Presumably therefore, the cost of regulatory compliance is already captured in SA Power Networks' existing expenditure and there is little justification for an additional $222 million to meet its regulatory obligations.

Moreover, as suggested by the AEMC in its 2013 rule amendments (see Section 3), it is up to the Government of SA and the relevant energy authorities such as ESCoSA and the OTR, to respond to the VBRC recommendations to the extent they see them as appropriate policies for SA consumers and SA conditions. This would also provide an opportunity for SA Power Networks to present its CE research findings so that the Government and the other authorities can take these findings into account, as appropriate.

We would expect that in the event of any material changes in SA regulations, SA Power Networks would be able to apply to the AER for a pass-through of additional costs.

This is particularly the case if SA Power Networks' proposed actions are pursuant to the VBRC recommendations, which, if taken literally, would cost SA electricity consumers many hundreds of millions of dollars.

The Victorian Government recognised the potential impact on consumers of the VBRC recommendations. The Victorian Government therefore established the Powerline Bushfire Safety Taskforce (PBST) as a multi-disciplinary team to advise on the most cost effective way to respond to the VBRC recommendations, including the timing and funding of such a response and investigation of new technologies.[54]

Following the initial investigations of the PBST, the following conclusions were drawn:

- There was a need to further investigate the most cost effective ways to address the issues identified by the VBRC;
- The response to the VBRC should be spread over a number of regulatory periods to reduce the impact on electricity costs; and
- Electricity consumers should not incur all the additional costs of remediating the electricity network. Both local councils and the Victorian Government (through the Powerline Replacement Fund) would contribute funding to the project.

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[54] The PBST is supported by a Stakeholder Reference Group and a Victorian Government interdepartmental Working Group, Members of the PBST and Working Groups have a broad range of skills in network and non-network technology solutions, bushfires, risk management and consumer behavior. The PBST commissioned consumer research and undertook various field trials as part of prioritising actions to reduce risk of bushfire starts from power lines.

The Victorian Government noted at the time:[55]

> *A process is required whereby* ***Government, safety agencies and electricity distribution businesses can work together to identify, and replace, the most dangerous power lines****. This will require an assessment of local bushfire risk; the condition of existing electricity assets; and a decision as to which replacement technology (insulation, aerial bundling, undergrounding) will yield the best result.* [emphasis added]

This approach is in marked contrast to the unilateral proposal by SA Power Networks in which electricity consumers would bear all the costs.[56]

Included in SA Power Networks' proposal for safety capex, was some $129 million for undergrounding program in high bushfire risk areas (HBRA). This included undergounding of power lines to 12 Bushfire Safer Precincts. Given SA Power Networks is using the VBRC recommendations as a benchmark, we would point to the fact that undergrounding in HBRA areas such as the Otway Ranges in Victoria was 100 per cent funded by the Government through the Powerline Replacement Fund.

In contrast, SA Power Networks' proposal puts the entire cost burden on electricity consumers and it is not clear if there has been an evaluation and optimisation of all the alternative funding options in SA Power Networks' proposal.

SA Power Networks' CE research also did not appear to set out the various options in terms of the priority, timing and cost allocation amongst different responsible bodies. Identifying that electricity consumers are willing to pay for additional bushfire remediation activity does not tell you what is the most optimal approach to addressing this issue in a practical sense and who and how costs should be shared. Thus, even if the CE program is a reasonable indication of unbiased consumer preferences (and it is not clear if consumers were fully informed and understood the full regulatory context) it is a large leap to translate those findings into a very large increase in capex (and opex)

In general, the AER has taken a similar view in its PD. The AER noted that, unlike Victoria, there are no specific <u>new</u> legislative requirements in South Australia that required SA Power Networks to undertake <u>additional</u> activity over and above SA Power Networks' existing prudent practices.

However, if SA Power Networks believes there is case to be made for <u>additional</u> expenditure on bushfire management, then perhaps a first step is to talk directly with the SA Government, the OTR and others to develop an integrated and properly funded program building on the PBST experience and its sponsored research. SA electricity

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[55] Victorian Government, Power Line Bushfire Safety: "Victorian Government Response to the Victorian Bushfires Royal Commission Recommendations 27 and 32", December 2011.

[56] CCP2 is aware that SA Power Networks states it has discussed its proposals with, for instance, the Country Fire Authority and local councils. However, this is very different than a multidisciplinary working group such as the Victorian PBST with all participants contributing experience and funding to the project.

consumers could then feel confident that the project is proceeding on the most cost effective basis with wide-spread community and government input and support. The previous quotation from the AEMC indicates that they consider this approach to be the most appropriate action if "maintaining" the current safety levels is considered insufficient.

For these reasons, the CE program is not a sufficient basis to undertake a project of such high cost to consumers and importance to the state. On this basis, it is recommended that the AER should not accept the total of SA Power Networks' revised proposal for "safety" augmentation expenditure.

Recommendation:

The AER does not accept SA Power Network's revised proposal for safety augmentation capex in its FD. This includes safety expenditure on additional bushfire mitigation and the undergrounding of the network in high-risk areas.

However, there appears to be some merit in SA Power Networks' proposed expenditure of $18 million on replacement of non-SCADA reclosers. SA Power Networks states that this expenditure will enable them to more effectively isolate specific regions of the network in the event of bushfires.

Currently, the regulations allow SA Power Networks to cut off electricity supply to a nominated region on very high bushfire risk days. SA Power Networks also states, however, that the current equipment requires manual operation, is slow to respond and when in operation, cuts off electricity to a wider area than necessary. As a result, SA Power Networks rarely exercises this right.

If the installation of reclosers enables SA Power Networks to manage this process more efficiently (and therefore use it more often) then such expenditure would seem to be a prudent approach to reducing bushfire hazards. It is with the AER to consider if this requires additional funding or can be funded adequately out of the overall capex budget (whether as replacement or augmentation).

Recommendation

The AER reconsider the merits of SA Power Networks' revised proposal for $18 million capex for remote controlled reclosers in regional areas as this will assist SA Power Networks' more effectively use its statutory powers to cut off electricity supply during periods of very high fire danger.

More generally, the fact that SA Power Networks may not receive specific funding for enhanced bushfire management does not mean that SA Power Networks must wait on the SA Government, ESCoSA or the OTR to initiate new regulations (should they choose to do so).

As noted above, the AER has allowed a substantial boost to SA Power Networks' replacement expenditure allowance compared to the past. There is nothing to stop SA

Power Networks placing a high priority on using replacement expenditure in areas of high bushfire risk if it is concerned with its general duty of care responsibilities.

The fact that SA Power Networks has largely completed the replacement of its upstream assets (substations and transformers – see above) means that much of its replacement capex can now be directed at replacing and upgrading down stream assets including dangerous overhead powerlines and switches in vulnerable areas, an area that appears to have been relatively neglected given SA Power Networks focus on upstream assets in 2010-15.

CCP2 does not accept SA Power Networks' characterisation that expenditure related to bushfire risk management should be solely treated as a separate category under "augmentation" and that it should not also be included as part of the capex "replacement" category. This is an artificial allocation by SA Power Networks and creates the risk of double counting the relevant expenditures. For example, if aging or poor condition assets (such as reclosers) are marked for replacement under the "repex" model and they are in a HBRA, is it captured under replacement expenditure or "safety" expenditure, or both?

In other words, it just makes good sense to prioritise replacement capex not only according to its condition or age, but also the location of the assets and the extent of harm if the asset fails. Similarly, replacement of assets in rural areas where there is a radial network might have a higher priority than replacement in a meshed section of the network where a failure in one component can be quickly resolved by rerouting. At the end of the day, these are business decisions around the allocation of funds rather than needing additional capex funding.

A number of regions in SA that are experiencing very poor reliability (such as the Wakefield region) would qualify as a priority under such an approach and the AER's decision does not prevent SA Power Networks prioritising its projects according to such criteria it sees as achieving the overall best outcomes.

In this respect, this paper supports the AER's reasoning and, in addition, reiterate that SA Power Networks' CE research may provide a guide to setting priorities for replacement expenditure, or at least be one element in SA Power Networks decision-making.

5.4.3.4. Undergrounding of powerlines

SA Power Networks has a relatively high proportion of assets (in terms of $ value) under ground, including powerlines that have been put underground as part of the Power Line Environment Committee (PLEC) program.

SA Power Networks' revised proposal suggests a substantial commitment to and preference for undergrounding power lines, that goes beyond the PLEC commitments and the proposed undergrounding in high bushfire risk areas of the state.

Figure 5.7 illustrates SA Power Networks' revised proposal for growth in circuit length for overhead and underground wires of different voltage. As discussed previously, there is minimal net growth in overhead line, but some 2,500 km increase in total underground circuit line, particularly in low voltage distribution (total km increase) and 33 kV (total percentage increase).

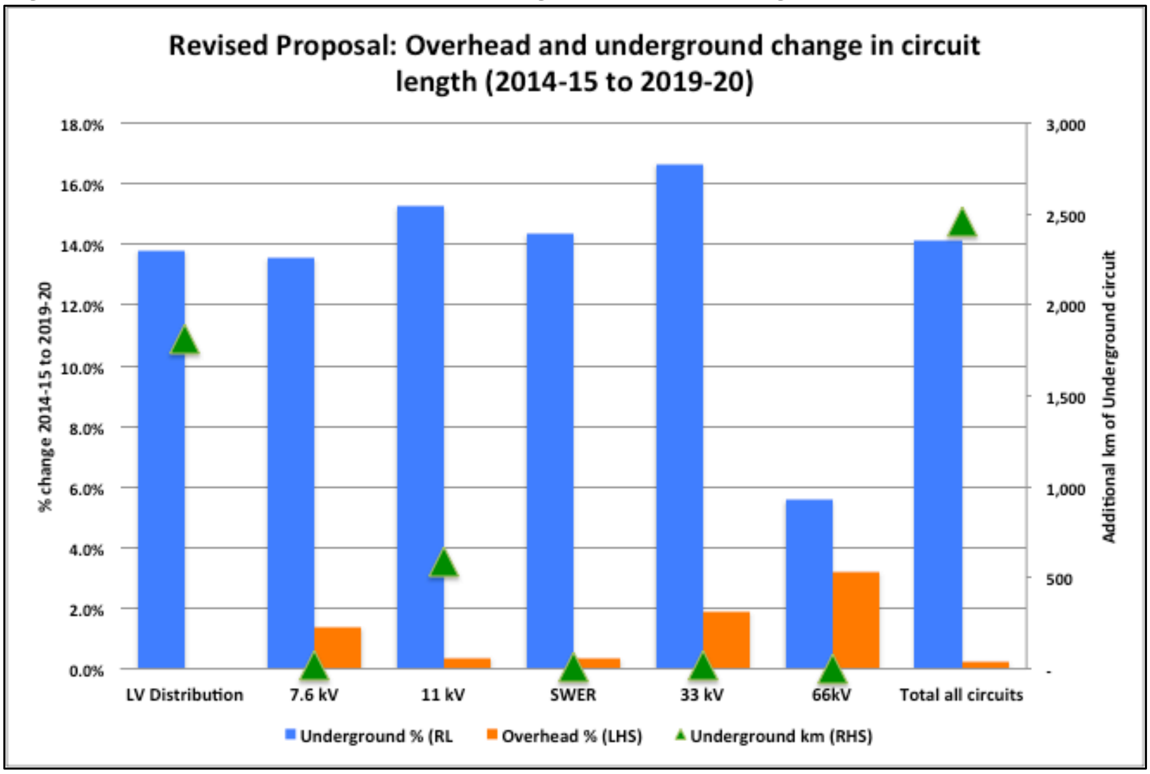
An equivalent assessment (not illustrated) of changes in capacity over the 2015-20 RCP, indicates minimal change in capacity for both underground and overhead circuits (less than 1 per cent in any voltage category).[57]

Power Line Environment Committee (PLEC)

As noted above, at least some of SA Power Networks undergrounding has been undertaken under the umbrella of PLEC. PLEC has broad representation including representatives from Government, Department of Planning, Transport and Infrastructure (DPTI), local councils, town planners and community representatives as well as a representative from SA Power Networks.

PLEC is tasked with setting priorities for funding undergrounding of power lines associated with amenity and road safety. It has an annual budget that is approximately two thirds funded by SA Power Networks. The AER provides a regulatory allowance for SA Power Networks' PLEC commitments. However, councils also contribute around one third of the budget and, where applicable, DPTI must contribute certain funds and works. The relevant Minister must endorse all PLEC projects.[58]

Figure 5.7: Growth in overhead & underground circuit length from 2015 - 20.



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57 From SA Power Networks, Revised Reset RIN 2015-20 – Public - July 2015- Physical Assets, Tables 3.5.1.1, 3.5.1.2, 3.5.1.3, 3.1.5.4.

58 See PLEC, "Project Guidelines", Issue 6, January 2013.

Source: SA Power Networks, Revised Reset RIN 2015-20 – Public - July 2015- Physical Assets, Tables 3.5.1.1, 3.5.1.2. CCP2 Analysis.

In CCP2's previous submission, we indicated support for a model such as the PLEC model, particularly for special projects such as the proposed undergrounding of power lines associated with the 12 "Bushfire Safer Precincts" that forms part of SA Power Networks proposed safety capex.

PLEC (or some equivalent body) brings a multidisciplinary approach to the assessment, where the AER is restricted by the expenditure objectives and criteria to a more narrow assessment. Therefore, in our previous submission CCP2 suggested that SA Power Networks could seek funding for projects like Bushfire Safer Precincts as part of the PLEC process.

In its revised proposal, SA Power Networks responded that PLEC's primary function is to prioritise expenditure on the basis of public amenity and transport/electrical safety planning criteria rather than (for instance) bushfire safety.

SA Power Networks point is acknowledged in this paper. However, the PLEC model of decision-making could still be usefully extended to considering questions about where and when to prioritise expenditure in rural areas to reduce bushfire risk and to decisions about undergrounding power lines to "Bushfire Safer Precincts".

In particular, a broad community based evaluation approach is generally better placed to assess the costs and benefits and the relatively priorities of the community on an objective basis using their collective experience gathered over many years, similar to the Victorian PBTF.

An expert panel could also provide a systematic way of assessing the costs and benefits of undergrounding versus alternative technologies such as the roll-out of an insulator conductor system in HBRAs. As noted above, there is research being undertaken in Victoria (as part of the overall response to the VBRC) into the most cost effective approach and it would be useful for the SA community to have the opportunity to consider how this might apply to SA.

This is a preferable, and more transparent approach than making decisions that rely only on customer surveys and WTP studies conducted at a particular point in time.

Road Safety Program

It is pleasing that SA Power Networks is no longer seeking additional allowances for undergrounding powerlines in road safety 'black spots' in the revised regulatory proposal.

As the AER noted in its PD, addressing road safety issues is not part of providing the regulated network services, nor should it be considered as a cost borne solely by electricity consumers. Of course, it is expected that SA Power Networks would work closely with road safety authorities (and it appears they do), but it is the primary responsibility of the road safety authorities to direct any changes in the arrangements.

The comments in the submission by the SA Minister for Mineral Resources and Energy are also most germane to this issue:[59]

> *…rather than embarking on a program that directly impacts on electricity prices, the Government submits road safety initiatives* ***are best left to expert agencies such as the Department of Planning, Transport and Infrastructure and the Motor Accident Commission*** *to determine if undergrounding or relocating power lines is the most viable option available to protect South Australian motorists in specific locations*. [emphasis added]

The Minister's response also affirms an important principle that is applicable more generally with respect to the allocation of responsibilities between various authorities and this principle. For instance, it is a very relevant principle for assessing proposals for undergrounding in bushfire risk areas and other safety measures proposed by SA Power Networks as discussed in section 5.4.3.4 above.

In particular, it provides a context for assessing if, and under what conditions, CE findings should be incorporated into SA Power Networks' regulatory proposals.

5.4.3.5. How can consumer concerns and CE studies be used in network regulation and planning?

SA Power Networks' CE program identified that consumers were concerned about bushfire safety and road safety. In the context of the WTP study, consumers also indicated some willingness to pay for programs such as additional undergrounding in HBRAs (capex) and improved vegetation management (opex).

In sections 5.4.3.3 and 5.4.3.4 above, it is suggested that for these types of programs that before SA Power Networks and/or the AER allocates <u>additional</u> funding to these proposals the following criteria should be satisfied:

- It has demonstrable support across government and community;
- It brings in expertise from a range of technical disciplines, councils and community representatives;
- Different funding arrangements are carefully considered, including shared funding;
- There is objective assessment of the most cost-effective alternatives;
- There is an effective business plan with achievable timelines for delivery of the benefit to households; and
- The outcomes are clearly defined and measurable; this includes not only output measure such as km of underground installed per year, but outcome measures such as number of fire starts reduced per year for "$X" investment.

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[59] SA Minister for Mineral Resources and Energy, "Submission to SA Power Networks' regulatory proposal", January 2015, p 4.

- The outcomes are linked to the incentive regulatory framework through mechanisms, for example, something similar to the Victorian "F-factor" scheme.[60]

It is reasonable to conclude therefore that when considering substantial additional capex (or opex), a proposal must go well beyond relying on a CE program; including WTP studies. This is one input into the decision, but there are many other considerations, a number of which have been described in various sections of this paper.

For example, participants in the CE studies may not have had sufficient expertise to understand responsibilities for different operational and funding aspects of a particular program (as per the quote from the SA Minister for Minerals and Energy).

Nor would CE participants generally be as aware of what other actions may have delivered more cost effective outcomes than (say) undergrounding across HBRAs. For example, the SA Government's submission refers to the advice of SA Power Networks' own consultant's that an insulated conductor system may be more cost effective in HBFRAs than broad scale undergrounding of lines. [61]

The comments by AusNet Services in relation to its CE research studies are also relevant to this issue: [62]

> *Undergrounding was commonly raised as an option* [for managing bushfire risk] *but there was widespread ignorance of the substantial cost increment of such a solution to an overhead system.*

And:

> *While strong support was expressed for undergrounding existing conductors, we consider the Victorian Government's Powerline Relocation Fund is the appropriate mechanism* ***as this spreads costs across the entire Victorian community*** *and the total* ***investment has been established using an appropriate cost benefit analyses.*** [emphasis added]

This does not mean that CE research has no part to play in the process, particularly if it is demonstrably unbiased in the way the research is framed to the participants and they have a reasonable level of knowledge of the industry structure and regulatory framework. For example, the CE research could potentially have value in a number of important areas, including (but not only):

- Assisting SA Power Networks in setting priorities for its replacement and augmentation capex (and opex);

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[60] The "F-factor" incentive scheme includes an objective output measure (number of fire starts caused by electricity assets)

[61] SA Minister for Mineral Resources and Energy, "Submission to SA Power Networks' regulatory proposal", January 2015, p 5.

[62] AusNet Services, *Electricity Distribution Pricing Review, 2016-2020*, April 2015, pp 54-55.

- Input to government policy and for DPTI, ESCoSA, OTR, PLEC and other relevant bodies to take into account in their decision-making, including consideration of additional funding for programs that have a positive net benefit;
- Prompt additional research (e.g. with Victoria) on the most cost-effective way to achieve the same outcomes that can be also measured objectively in terms, for example, of the number of bushfire start reductions or traffic accident reductions;

In the context of a CE research study it is also not reasonable to expect consumers to understand the long-term implications on their electricity bills of building new assets (see AusNet quote above). Nor might they understand the relationships between the inputs they are willing to pay for and the outputs that might be achieved.

For example, SA Power Networks indicates that the plan to underground 135 km of power line in bushfire safe precincts and HBFRAs would require a capex spend of around $129 million dollars over five years and would increase the percentage of total power lines in HBFRA areas from 11.11% to 11.92%.[63] An objective business case would assess this cost and gain against the reduction in <u>actual outcome risks (number of bushfires avoided et al)</u>.

However, in the context of a CE research study, consumers may differ in their response depending on whether the question is phrased in terms of $ per year additional network price, [64] or in terms of the increase in % of total underground powerlines in HBFRA areas.

Consumers may have given yet another response to undergrounding if the issue was put to them in terms of $129 million dollars (to be paid off over 40 years at, say, 9 per cent per annum interest) for an additional 135 km underground powerlines resulting in an average annual reduction of X% in fire starts due to electricity assets.

5.4.3.6. Costs of undergrounding

In this context, it is also important to consider the concerns expressed by PLEC in the past regarding the escalation of costs that have been charged to the PLEC program by SA Power Networks for undergrounding work.

PLEC stated that these higher costs have significantly reduced the extent of their programs.[65] In the 2013-14 period, PLEC approved nearly 7 km of undergrounding for a total cost of around $14 million ($2013-14), including $9.4 million from PLEC (funded

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[63] SA Power Networks, *Bushfire Mitigation Programs Business Case*, Attachment 20.45, October 2014, p 29.

[64] In the WTP research, consumers were given an estimate of annual dollar cost per customer of various combinations of service, where the cost increments were based on advice from SA Power Networks.

[65] PLEC, Power Line Undergrounding Review and Plan, August 2010, p 3. PLEC highlights that the cost of undergrounding had increased from $609/metre in 2000 to $1237/metre ($2009/10) in 2010, halving the distance undergrounded from 14 km/year to 6.7 km/year although expenditure in Metropolitan areas declined significantly.

by SA Power Networks) and $4.6 million funding from councils.[66] The most recent public information from PLEC suggests that SA Power Networks (excluding council contributions) current cost for undergrounding is around $1,300,000 - $1,400,000 per km ($2015).

CCP2 notes that this estimate from PLEC data of undergrounding costs is considerably higher than the estimate in the SA Power Networks business case referred to above ($129 million for 135 km of underground power line or $955/km ($2015)). It would be worthwhile the AER conducting further investigation of these differences and whether SA Power Networks expects a contribution from councils for this extended program given that it goes beyond the PLEC mandate.

It is not readily possible to assess these costs, or to compare them with the costs of undergrounding for other distribution businesses. However, it does indicate how difficult it is to translate SA Power Networks' CE program into a regulatory expenditure proposal, particularly when the regulatory expenditure objectives are focussed on compliance with regulations and maintenance of safety performance.

This all suggests that there must be very strong evidence of changes in circumstances (regulatory or environmental) to justify an expansion of existing levels of expenditure.

Recommendations:

The AER reconsider the merits of SA Power Networks' revised proposal for $18 million capex for remote controlled reclosers in regional areas as this will assist SA Power Networks' more effectively use its statutory powers to cut off electricity supply in periods of very high fire danger.

The AER provide more detailed benchmark information on the comparative costs of undergrounding across different DSNPs, and costs of alternative technologies to address exposure high bushfire risk areas.

The AER investigate SA Power Network's proposal to extend its underground network by 14 per cent, while not extending its overhead network, particularly as the cost of undergrounding is so much greater and adds significantly to the RAB.

5.4.4 Reliability augmentation capex.

5.4.4.1. The AER's PD and SA Power Networks' revised proposal

SA Power Networks sought some $59 million ($2015) for reliability capex as part of its overall augmentation capex in its original proposal for 2015-20. This amount is more than double the approved allowance of $25 million for 2010-15.

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[66] PLEC, Annual Report, 2013-2014, August, 2014, p 6. PLEC contributed $9.4 million; councils contributed $4.7 million (see Table 1). DPTI contributed around $0.8 million.

The AER's PD granted less than half of that amount ($28 million). However, SA Power Networks' revised proposal includes some $60 million capex for reliability augmentation capex.

While the AER accepted SA Power Networks' proposed expenditure to maintain reliability, the AER rejected SA Power Networks' proposals for an additional $30 million to improve network reliability over SA Power Networks' current reliability performance level.

The AER noted that SA Power Networks' reliability performance after excluding major event days (MEDs) is consistently meeting the reliability targets set by ESCoSA for overall performance and at the regional level.

SA Power Networks did not accept the AER's PD position. It considered that consumers support its program to "harden" the network against extreme weather events and other MEDs.[67]

SA Power Networks also states that it has customer and community support for improving supply to the worst performance areas in the state as well as an expectation from ESCoSA that reliability performance on the worst performing feeders: "should not deteriorate further, but rather return to the mandated regional targets".[68]

SA Power Networks considers that the cost of this will not be recovered through the AER's STPIS program. In particular, SA Power Networks claims that the various additional reliability programs (above the standard reliability targets) have a net present value over a 35-year period to customers of $54 million using the latest Value of Customer Reliability (VCR) values from Australian Energy Market Operator (AEMO).[69]

However, SA Power Networks also claims that there is little benefit to SA Power Networks of such a program (unless funded by the AER) as it makes no or little change to its STPIS outcome. [70]

5.4.4.2. Response to reliability augmentation capex

In the first instance, SA Power Networks appears to be ignoring the fact that it has been allocated a generous overall capex allowance particularly with respect to replacement and demand related augmentation capex.

These additional allowances, when combined with the decline in the need for growth capex, the previous increase in replacement capex and renewal of distribution and zone

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[67] SA Power Networks, *Revised Regulatory Proposal*, July 2015, p 116.
[68] Ibid, p 118.
[69] Ibid, p 122.
[70] Ibid. The assessment includes the low reliability feeders and Hawker-Elliston programs. SA Power Networks claims the overall STPIS outcome from the programs is "neutral" with a "potential for a slight positive outcome of about 0.02% of revenue.

substations during 2010-15, provide an excellent opportunity for SA Power Networks to shift its priorities.

That is, SA Power Networks should be in a very good position to prioritise its expenditures in line with the priorities of its customers as expressed in SA Power Networks' CE program and the feedback from other parts of the SA Government and community (including submissions on the 2015-20 regulatory proposals).

Just because consumers in a CE study express a support for a program to harden and protect the network and improve the supply reliability for remote communities does not per se mean additional capex is required in total. The CE program provides a useful guide for SA Power Networks about its allocation of funds, but not necessarily a guide to the AER about the total quantum of funds that is consistent with the NER.

Normalised Reliability Standards

In our previous submission to the AER, CCP2 suggested that there was no compelling evidence that SA Power Networks' reliability was declining once the impact of MEDs was removed.

While SA Power Networks breached its performance targets in a number of regions in 2013-14, ESCoSA was satisfied that SA Power Networks demonstrated "best endeavours". Table 5.2 illustrates this point.

Table 5.2: SA Power Networks' performance against interruption service standards

REGION	DURATION OF INTERRUPTIONS 2013–14			FREQUENCY OF INTERRUPTIONS 2013–14		
	TARGET (minutes)	PERFORMANCE (minutes)	BEST ENDEAVOURS	TARGET (frequency)	PERFORMANCE (frequency)	BEST ENDEAVOURS
Adelaide Business Area	25	9	●	0.25	0.12	●
Major Metropolitan Areas	130	265	●	1.45	1.72	●
Central	260	242	●	1.80	1.59	●
Eastern Hills/Fleurieu Peninsula	295	425	●	2.80	2.90	●
Upper North/Eyre Peninsula	425	390	●	2.30	1.69	●
South East	295	428	●	2.50	2.45	●
Kangaroo Island	450	385	●	N/A[1]	-	N/A[1]
State-wide (implied)	**179**	**287**	●	**1.68**	**1.83**	●

Source: ESCoSA, *Performance of SA Power Networks 2013-14, Report 2*, 2014, Table 2, p 2.

Further examination of ESCoSA's various distribution performance reports confirm this view. The AER's PD also provides evidence to this effect.

In particular, ESCoSA's more recent reliability performance reports, viz: (i) Summer 2014/15 Performance Report, and (ii) March 2015 Quarter Operational & Performance

Data provide a more up to date snap shot of the reliability performance of the network overall and various parts of the network.

Neither of these recent reports demonstrate declines in the measures of total state SAIDI and SAIFI,[71] nor do they demonstrate a persistent decline in any particular region of the state. In the quarterly performance report ESCoSA concludes that: "…on a year to date basis, all regions except the Central region are well under the annual performance targets", even though most of the regions experienced severe weather events between January and March 2015.[72]

We therefore remain of the view that no additional expenditure above the AER's allowance is required to maintain the "normalised" reliability performance levels at their current level and to meet the standards set by ESCoSA and by the AER's performance incentive scheme, STPIS.

As noted previously, the AEMC's 2013 amendments to the NER clarify that an NSP must be provided with sufficient funds to comply with relevant standards but this does **not mean** that additional funds should be provided for performance in excess of the relevant jurisdictional or national standards, not withstanding any CE research.

The AEMC stated:[73]

> *… [i]t should be made clear in the NER that where the jurisdiction determines a regulated standard for reliability, it is this level of reliability that expenditure in an NSP's regulatory proposal should be based on* ***and not on any other level****.* emphasis added]

Similarly, the AEMC stated that the assessment applies not only to service standards, but also to quality and security of supply. Thus, the AEMC's 2013 exposition is relevant to the question of funding for additional performance as discussed in Section 3 and explained further below.

Improving response to MEDs

The question then becomes whether SA Power Networks should undertake **additional** expenditure, specifically to improve performance during MEDs. If so, how much should that be undertaken and what actions would prove to be the most cost effective.

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71 System average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI)

72 ESCoSA, "SA Power Networks' Operational & Performance Data – March 2015 Quarter", p 3. http://www.escosa.sa.gov.au/electricity-overview/reporting-and-compliance/sa-power-networks-statistical-updates/sa-power-networks-operational-performance-data-march-2015-quarter.aspx

73 AEMC 2013, *Network Service Provider Expenditure Objectives, Rule Determination*, 19 September 2013, Sydney, p 15.

In the first instance, by SA Power Networks' inference that ESCoSA is expecting improved performance by SA Power Networks during MEDs is somewhat puzzling. SA Power Networks states:[74]

> *Consistent with its historical approach, ESCoSA will focus on our performance during MEDs in the 2015-20 RCP.* ***It is ESCoSA's expectations that our performance during MEDs and the associated severe weather events will not decline but improve.***

SA Power Networks also states:[75]

> ***To mitigate the deterioration in our reliability performance attributable to MEDs,*** *SA Power Networks proposed to harden our network in locations that are consistently affected by lightening and wind storms which resulted in MEDs.*

However, ESCoSA's reports do not indicate that it has formally requested SA Power Networks to "improve" its performance in response to MEDs, although ESCoSA has state that it would not like to see any deterioration in SA Power Networks' response to MEDs. ESCoSA also is pragmatic about the issue and does not appear to be looking to impose new standards that will increase costs to consumers.

Recommendations:

The AER discuss with ESCoSA whether it is expecting SA Power Networks to maintain, or in the alternative, improve the performance of the distribution network during MEDs. If this is the case, then ESCoSA's new standards might be made more explicit.

The AER, in conjunction with ESCoSA, consider ways in which performance during MEDs can be appropriately included in any incentive scheme, if it agrees that MEDs performance is an important measure of network performance.

Hardening the network

Hardening the network to resist storms over and above the normal replacement and augmentation activities would prove extremely costly and is only necessary if ESCoSA reports a significant and sustained deterioration of SA Power Networks' response to MEDs events.

Of course, this does not prevent SA Power Networks making its own decisions to harden different sections of its network on a cost benefit basis (such as reduced opex or Guarantee Service Level Payments (GSL)[76]) or to incorporate these principles into its

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[74] SA Power Networks, *Revised Regulatory Proposal 2015-20*, July 2015, p 111.

[75] Ibid.

[76] While the STPIS measures are adjusted to exclude MEDs, the GSL payments are required irrespective of the cause of the event.

ongoing replacement program. However, this is a business decision and does not require the AER to approve additional funds.

ESCoSA does require SA Power Networks to satisfy a "best endeavours" test for meeting the reliability standards for the state in general, and for designated regions in the state as illustrated in Table 5.2 above.

ESCoSA also monitors SA Power Networks' response to MEDs
. As ESCoSA states in its 2013-14 Annual Performance Report: [77]

> *Where a target is not met, this does not necessarily mean the standard is not met. The standard may still be met if SA Power Networks can show that it* ***used its best endeavours in trying to meet the target.*** [emphasis added]

ESCoSA's 2013-14 report also states that throughout the year it monitors SA Power Networks' performance during severe weather events and: [78]

> *Supply restoration times during widespread interruption caused by severe weather events should be minimised through appropriate resourcing, efficient call centre operations and dispatching crews.*

With reference to a severe summer event in summer 2013-14, ESCoSA concludes: [79]

> *SA Power Networks took appropriate steps prior to the severed weather events to ensure resources would be available if required, and that it directed appropriate resources (including utilisation of interstate assistance) in repairing the extensive damage to its network caused by severe weather events over 2013-14 summer.*
>
> *…*
>
> - *SA Power Networks was appropriately resourced to respond to anticipated outages caused by the forecast severe weather events.*
> - *…*
> - *during these events, SA Power Networks responded appropriately and effectively in systematically restoring supply to customers.*

Clearly, there is much that SA Power Networks can be proud of in its ability to manage the challenges of weather related supply interruptions. However, this does not seem to be a basis for providing SA Power Networks with an n additional allowance over and above the replacement and augmentation allowances approved by the AER in the PD.

Furthermore, there is no clear evidence of a long term trend in severe weather events. Although 2013-14 had up to four very severe and wide spread adverse events, the pattern is not consistent and the number of events appears to have declined in 2014-15.

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[77] ESCoSA, "Performance of SA Power Networks, Report 2, 2013-14", p 1.

[78] Ibid, p 2.

[79] Ibid, p 3.

The SA Government in its submission to the AER, undertook an assessment of weather trends and interruptions due to weather as set out in Table 5.3.

Table 5.3: Historical trends in average % of interruptions caused by weather.

Period	Average % of interruptions caused by weather
2000 – 2005	37%
2005 – 2010	32%
2010 – 2014	35%

Period	Average % of interruptions caused by weather
2011 - 2012	27%
2012 – 2013	29%
2013 - 2014	42%

Source: Government of South Australia, "Submission to the Australian Energy Regulator on the SA Power Networks' Regulatory Proposal 2015-2020", January 2015, p 7.

The SA Government noted the increase in 2013-14 but did so in the context of the longer-term trends and overall community satisfaction with electricity reliability in SA. The Government concluded that:[80]

> *…[t]his analysis shows that the number of average interruptions caused by weather* ***has remained relatively stable from 2000*** *and therefore we would question the need for an increase of expenditure for reliability against weather events by more than double from the previous regulatory period.* [emphasis added]

The SA Government's reasoning appears to be sound and the most recent quarterly performance report from ESCoSA (that includes the summer of 2014-15) indicates that 2013-14 was something of an anomoly.

Table 5.4 below provides a summary of ESCoSA's analysis from the most recent quarterly performance report. In this report, ESCoSA presents the reliability results year to date for 2014-15 as a percentage of the total year's reliability "target" for each of the seven designated electricity supply regions in SA. The Year to ate figures represents the percentage of the target reached by the end of the third quarter of the financial year.

[80] Government of South Australia, "Submission to the Australian Energy Regulator on the SA Power Networks' Regulatory Proposal 2015-2020", January 2015, p 7.

Table 5.4 demonstrates that in all regions, SAIFI is well below 75 per cent of ESCoSA's regional targets and all but one region is similarly below 75 per cent of the SAIDI target (noting that as most MEDs occur in summer, 75 per cent is a conservative reference point).

Table 5.4: Percentage of SAIDI & SAIFI targets expended to end of Quarter 3 2014-15, by SA region

Region	Adelaide CBD	Major Metro	Central	Eastern Hills & Fleurieu Peninsula	Upper North & Eyre Peninsula	South East	Kangaroo Island
% SAIDI Target Expended	20%	60%	91%	62%	66%	58%	50%
% SAIFI Target Expended	26%	49%	45%	19%	23%	46%	0%

Source: ESCoSA, *SA Power Networks' Operational & Performance Data, March 2015 Quarter*, pp 3-4., CCP2 analysis.

SA Power Networks also claims in its revised proposal that ESCoSA expects that: "our performance during MEDS and severe weather events **will not decline but improve in order to meet mandated regional targets in 2015-20 RCP**".[81] [emphasis added]

However, ESCoSA's public statements (as set out above) indicate that it is reasonably satisfied with SA Power Networks' performance in respect of MEDs and severe weather events. Just as we have not seen reference to ESCoSA seeking better performance during MEDs (see above), we have not seen reference to ESCoSA requiring improvements to meet mandated regional targets during adverse weather conditions.

Again, this paper must emphasise that nothing prevents SA Power Networks undertaking additional hardening of its network systems and, for instance, the increased replacement capex allowance provides funding for SA Power Networks to do so if it chooses to prioritise this activity. SA Power Networks' CE program suggests that consumers have a preference for this, however, it does not automatically mean that acting on that preference requires additional funding rather than simply priorisation.

Alternatively, SA Power Networks may find it beneficial to invest additional capex above its AER allowance and thereby save in opex, particularly given SA Power Networks' statements on the extra costs of servicing regional and remote customers. This is a choice that SA Power Networks is best placed to make, particularly after

[81] SA Power Networks, *Revised Regulatory Proposal 2015-20*, July 2015, p 119.

taking into account potential benefits from the incentive schemes (EBSS in particular) and reduced GSL payments.[82]

Low reliability distribution feeders (LRDFs)

SA Power Networks has identified some 30 high voltage feeders that consistently perform below ESCoSA's regional reliability standards. SA Power Networks proposes an additional capex allowance of some $8.1 million to upgrade these low reliability feeders. [83]

SA Power Networks also claims that its CE research indicates that customers are prepared to pay for improving the services to the low reliability feeders. A number of regional and remote area councils have also responded favourably to SA Power Networks' revised proposal for additional funding to address low reliability feeders supporting the improvement of electricity reliability in their area.

In its revised regulatory proposal, SA Power Networks also states that ESCoSA has an expectation that reliability performance on the worst performing feeders: "should not deteriorate further, but **rather return to the mandated regional targets**".[84] [emphasis added]

Again, it has proven difficult to find public information to support the claim that ESCoSA expects **improvements in the performance** of the LRDFs to **meet mandated regional targets**. ESCoSA's approach appears to be far more realistic and does not require individual feeders to achieve the mandated regional target.

For example, ESCoSA states in its 2013-14 Performance Report regarding LRDFs:[85]

> *Remediation of LRDFs is dependent, to a degree, on the extent of **the benefit gained relative to the cost of the work**. Understandably there will be situations where the costs far outweigh the benefits. **There will continue to be parts of the network with lower reliability;** however, **SA Power Networks should ensure that reliability in these areas does not decline over time**. To some extent, GSL payments serve to balance the impact of poor performance for the poorest served customers.* [emphasis added]

As stated above, it is more than open to SA Power Networks to listen to its customers' concerns and prioritise its expenditure accordingly. That does not automatically mean

[82] Unlike the STPIS scheme which excludes the impact of MEDs, GSL payments must be made to customers whose service is interrupted irrespective of the causes of the interruption to their power supply.
[83] ESCoSA sets performance standards for each of the seven nominated regions in SA. Adelaide CBD have the highest standards while the more rural regions have lower standards for SAIDI and SAIFI, reflecting the distances involved and the nature of the network. See also Table 5.2
[84] Ibid, p 118.
[85] ESCoSA, "Performance of SA Power Networks, Report 2, 2013-14", p 7.

that additional expenditure allowances are required. All businesses must prioritise investment within capital constraints.

In a previous section of this paper, the concerns of rural and remote councils with a number of poorly performing feeders were acknowledged along with their express views that the AER should have allowed SA Power Networks additional funds to address these matters. However, there is no reason why SA Power Networks cannot address these concerns if it wishes to prioritise them, particularly given that much of the upstream assets have already been replaced in 2010-15. Moreover, SA Power Networks' CE research should provide guidance on whether SA Power Networks should allocate funds to this issue.

SA Power Networks' also holds the view that the number of customers in LRDF areas is so small relative that improvements to the network in LRDF areas are not likely to have a pay-off under the STPIS program. However there are other reasons (apart from meeting its customers' expectations) that SA Power Networks might choose to proceed with addressing the LRDF issues within its overall capex allowance:

- SA Power Networks has been remediating these areas for some time. Even though the number of LRDFs increased in 2013-14 (because of the very wild weather in that year), SA Power Networks had also managed to move a reasonable proportion of the feeders out of the LRDF category; and has done so within its regulatory allowances; [86]
- Improving these LRDF regions will reduce SA Power Networks' Guaranteed Service Level (GSL) payments. In 2013-14, SA Power Networks made a total of $9.4 million GSL payments, $6.3 million of which was made to customers as a result of one major severe weather event.
- Improvements in these regions will lead to a saving in maintenance and related opex costs as remediating powerlines in these more remote areas is more expensive.

Recommendation:

The AER not accept SA Power Networks' proposed additional capex on low reliability distribution feeders (LRDF). There is no evidence that current expenditure allowances have been insufficient to progressively address LRDFs or have led to a sustained decline in performance; nor has there been a directive from ESCoSA to improve performance.

Micro-Grid trial program

SA Power Networks intends to conduct a trial of a micro-grid technology in one of the more remote LRDF regions for a cost of $2.7 million ($2015) as an alternative to capex for upgrades. The AER queries the benefits of the trial, particularly if it is directed at

[86] Ibid, p 7. ESCoSA reports that in 2013-14 16 feeders that had been LRDFs for the previous three years improved performance and were no longer categorised as LRDFs in 2013-14.

improving reliability not just maintaining the current level reliability. In its revised proposal, SA Power Networks suggested that the trial had broader benefits but acknowledged that it could be used in only limited number of the LRDF regions.

Innovation is important, particularly when it can be demonstrated to be cost effective and consistent with achieving regulatory service standards. Therefore, the ongoing trial may have wider benefit. However, it is generally more transparent to fund the trial under the demand management incentive scheme (DMIS) rather than as part of the normal capital expenditure allowance process.

Recommendation

The AER and SA Power Networks decide whether the Micro-grid Trial Program is better funded through the DMIS, which will have the added benefit of providing greater transparency and industry learning from the trial.

5.4.5 Strategic augmentation projects[87]

5.4.5.1. The AER's PD and SA Power Networks' revised proposal

In its initial proposal, SA Power Networks sought a total of $97 million ($2015) for strategic augmentation projects. This represents a significant increase compared to actual expenditure in 2010-15 ($78 million nominal[88]). The largest components of SA Power Networks' strategic augmentation proposal were the second Kangaroo Island electricity cable ($47 million), network control ($26 million) and additional LV network and asset condition monitoring ($22 million).

The AER approved $47 million ($2015), rejecting all of SA Power Network's proposed strategic expenditure except for the additional electricity cable to Kangaroo Island. SA Power Networks' revised proposal of $80 million ($2015) includes all of the main elements of its original proposal for strategic capex, except for a reduction in the LV network and asset condition monitoring ($3.5 million).

5.4.5.2. CCP2's views on the strategic augmentation projects

Strategic Augmentation: Kangaroo Island

Kangaroo Island (KI) has a permanent population of approximately 4,600 people with around half living in the island's main town of Kingston. Electricity is supplied from

[87] Figures presented in this section are largely based on SA Power Networks, *Revised Regulatory Proposal 2015-20*, Table 7.7, pp 71-73. The numbers do not match the AER's PD because (inter alia) the treatment of overheads. $ amounts are in $2014 - 2015 unless otherwise stated.
[88] SA Power Networks, *Regulatory Proposal 2015-20*, Table 20.27, p 220.

the mainland by a single electricity undersea cable with on-island diesel generation as back up. Many business customers on KI also have their own back up generators.[89]

SA Power Networks has proposed to install a second undersea electricity cable to KI on the basis that the current cable, which was installed in 1993, is approaching the end of its 30-year design life. SA Power Networks claim that if the cable failed it would take a total of two years to order and install a replacement cable and thereby impose very high costs on and inconvenience to the community (using diesel back-up generation at an estimated cost of $32 million per annum to run).

The proposal to install a second undersea cable has previously been rejected by ESCoSA in 2005 and by the AER 2010. In the current PD, the AER has accepted SA Power Networks' proposal of $47 million capex ($2015), including SA Power Network's proposed costing for the project that has been provided to the AER in a confidential submission.

The AER's PD also stated that the project was expected to commence in 2018 and the final decision to proceed would be subject to a RIT-D consultation process that may identify cost effective alternatives to installing a second cable, including on-island renewable energy projects.

Response to the Kangaroo Island proposal

There are different views amongst stakeholders regarding the installation of a second undersea cable to KI. For example, Business SA considers the installation of a second cable is not appropriate in the 2015-20 regulatory period given the design life of the current installation and the lack of evidence of any significant deterioration of the cable. Business SA, the Total Environment Centre (TEC) and others consider there has been insufficient examination of alternatives to a second cable, noting that KI is a prime site for wind generation.

On the other hand, the SA Government recommends that the AER approve the installation of a new cable based on the importance of a reliable supply of electricity to the island and the potential costs of failure of the cable.

While the SA Government's policy position is understandable, there are also good reasons for a careful examination of options before there is a commitment to expenditure on a second cable.

In the first instance, SA Power Networks is seeking $45 million for the project in the 2015-20 period. However, it is not clear from the available information[90] what the

[89] See for instance, AER, *South Australia Draft distribution determination 2010-11 to 2014-15*, November 2009, p 147. The AER cited analysis by the Kangaroo Island Regional Development Committee. The AER also cited a report by Wessex Consult Pty Ltd that indicated private generation capacity was sufficient to provide some 99% of KI's peak demand, p 150.

overall costs of the project are. For example, SA Power Networks states that: "once the old cable fails the need to upgrade the power [Kingscote] station will be necessary to keep pace with the increasing KI demand".[91] Therefore the assessment should include the costs of the capacity upgrade to the Kingscote station if/when the existing cable fails.[92]

There are also substantial risks involved in investing such a significant amount of money in this type of single project and given the rapid growth in renewable technologies. Once built, the risk is that the cable may be underutilised while still remaining on SA Power Networks' asset base for 30 years (or more).

In the mean time, the new cable will have "crowded out" the opportunity to develop alternative energy sources on the island even though this may well provide a more sustainable, lower risk alternative over the longer term. For example, once the old cable fails, the situation for KI electricity supply reverts back almost to the current risk situation of a single cable and limited diesel back-up.[93]

In addition, CCP2 finds the AER's modelling of the cost-benefit of SA Power Networks' proposal problematic, although we acknowledge that we have not reviewed the study in full detail because the business case data is confidential. Our concerns include:

- The assumption of a linear probability curve increasing to 100 per cent when the cable reaches 30 years (although we note that SA Power Networks has subsequently modelled a normalised probability to failure curve which is more realistic);
- The assumption that "no repair of the existing cable is possible" and therefore, any cable failure results in two years of operation of the alternative on-island diesel generation;
- The (apparent) lack of scenario testing for different demand options and distributed generation/storage technologies, and the costs thereof;
- The ongoing need for back-up diesel generation under all scenarios; it is not clear how this has been taken into account in the context of each option in the study;[94]
- The sensitivity of the costing to the assumption that the first cable continues to function in parallel for a period of time (see above);

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[90] Including Attachment G.1a to SA Power Networks' Revised Regulatory Proposal. "Attachment,_SA Power Networks'_Kangaroo Island submarine cable –additional information", 3 July 2015.

[91] See ibid, p 9.

[92] This assessment should use the same probability of failure functional form as used in the main evaluation

[93] This is because the most likely scenarios of catastrophic and unrepairable failure of undersea cables is due to external damage – see also footnote 95 below.

[94] For example, an option of wind & expanded solar with diesel generation back up may or may not require more investment over the forward projections than installation of the new cable – absent the continued existence of the original cable, and the projected growth in demand, the same risks that exist now will largely continue impacting on the size of any new diesel generator. See footnote below for discussion on failure risks.

- The risk/probability of external events causing damage to the second cable (particularly if it is operating alone).[95]

It is hoped that these issues will be fully and transparently addressed as part of the RIT-D process. In the FD, however, there should be more transparency about the full life-cycle costs of the KI cable project across a 20-30 year period.

Recommendation:

The AER provide a full assessment of the total life-cycle costs of the second cable to Kangaroo Island, including any expansion of the Kingscote substation and additional on-island back-up generation in the event that only the new cable supplies the island.

The AER's conclusions regarding this expenditure as set out in page 6-68, Attachment 6 of the AER's PD is also not satisfactory. In response to various submissions opposing the second cable, the AER states that, under the NER:

> *[w]e either accept a distributor's total of forecast capex, or establish our own estimate of total required capex, for the relevant regulatory control period. From there, the requirement is on the network business to balance its opex and capex to meet its obligations. Accordingly, if the RIT-D consultation process discovers a more efficient non-network option, SA Power Networks is able to proceed with that option.* ***To the extent that the cost of the ultimate solution is less than forecast, the benefits will be shared with consumers through our capital expenditure sharing scheme…*** [emphasis added]

The first part of the quotation above is strongly supported. Indeed, the view that the AER provides an estimate of total capex and total opex with the network business responsible for balancing these expenditures to meet its obligations is one of the central principles pronounced in Section 3 of this submission. The RIT-D will provide another opportunity for proponents of alternative solutions to put these solutions forward for more detailed evaluation.

However, the capital expenditure sharing scheme (CESS) process referred to in the last sentence of the quotation above means that consumers still carry 30 per cent of the capex cost if SA Power Networks' actual capex is lower than the AER's allowance (i.e. if the new cable is not installed or is delayed beyond the current RCP). As the AER states in Attachment 10 of its PD regarding the CESS incentive mechanism: "This means that for a one dollar saving in capex the service provider keeps 30 cents of the benefit while

[95] In its submission, Business SA cites data from CIGRE, an international organization that indicates 85% of failures in undersea cables is caused by external damage. SA Power Networks suggests that this figure is not applicable to the KI cable and in any case, the second cable will be laid at a distance from the "existing cable reducing the probability of both cables being damaged in the same event." Ibid, p 7. CCP2 does not consider SA Power Networks' response adequately addresses the issue raised by Business SA. Business SA is assuming that the new cable is the sole provider to KI and as such, the same risk applies, as there is no back up other than the diesel generators and any other local sources of supply.

consumers keep 70 cents of the benefit".[96] If the KI project does not proceed, consumers would want to receive 100 per cent of the savings in capex, not 70 per cent.

For instance, if the "ultimate solution" following the RIT-D is (say) $10 million less than the allowed $45 million for a second cable, SA Power Networks will still receive an additional net benefit of $3 million above its actual capex outlay. [97]

In addition, and perhaps more importantly, the CESS only applies to differences in the aggregate level of capital expenditure, not at the project level. Using our example above, if the alternative proposal is $10 million less than "allowed"[98] by the AER, but SA Power Networks spends $10 million more on other projects, then there will be in effect no "benefit sharing" with SA consumers of this lower cost to reinforce supply to KI.

Overall, CCP2 considers that a project such this is best classified as "contingent project", albeit one subject to a RIT-D assessment. If it was classified as a contingent event, then if it goes ahead as planned in this regulatory period, SA Power Networks recovers the capital investment. If it does not proceed in the current regulatory period, or a lower cost alternative is found, then only that cost will be recovered from consumers. In this way, the AER will not be relying on the limited mechanisms in the CESS to deliver equity to consumers.

Recommendation:

The AER and SA Power Networks consider the option to include the KI cable as a contingent project under NER clause 6.6A.1(b) and 6.6A.1(c)(5)

Should a failure of the KI cable be a nominated pass through event?

Finally, CCP2 is concerned that SA Power Networks is also proposing that a failure of the KI cable be considered as a pass through event ("Kangaroo Island cable failure event").

The AER has rejected this proposal. However, SA Power Networks' revised regulatory proposal states that the AER is incorrect in this decision. SA Power Networks is arguing that the AER has recognised the risks and costs of such an event and states that it is: "unable to obtain appropriate insurances that are commercially viable for this type of event."[99]

The AER's position of not allowing a cable failure to be a specific pass through event is most appropriate. This is a reasonable risk and it is difficult to see why this type of

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[96] AER, *Preliminary Decision, SA Power Networks determination 2015-15 to 2019-20*, Attachment 10 – Capital expenditure sharing scheme, April 2015, p 10-6.
[97] That is: (1 – ($10*0.7)).
[98] "Allowed" is in quotation marks because as noted in many places, the AER does not in reality approve specific projects so much as an overall amount.
[99] SA Power Networks, *Regulatory Proposal 2015-20*, October 2014, p 275.

event would not be covered by SA Power Networks' general insurance or self-insurance.

Moreover, SA Power Networks has identified this risk of cable failure in its previous regulatory proposals but it does not appear to have been raised previously as an issue or that it is not insurable.

Beyond these specific concerns, it is a matter of principle that the "pass through" arrangements under the NER should not become a 'shopping list' covering many individual events. The terms of a pass through are better kept in general terms rather than specific items.

Recommendation:

The AER not accept SP Power Networks' proposal to nominate a failure of the KI cable as a "pass through" event.

Strategic Augmentation: Network Control

SA Power Networks' initial proposal includes capex of some $26 million ($2015) on network control, which SA Power Networks describes as "smarter network initiatives" and "SCADA Investment". SA Power Networks' intention was to extend its current network control and automation equipment and distribution management system to rural substations and switches.

The AER did not accept this expenditure. The AER stated that SA Power Networks had not provided sufficient evidence that additional network equipment is required to maintain service levels in 2015-20 period.

SA Power Networks' revised regulatory proposal includes $27 million for network control. The revised proposal, although costing more than the original proposal, is reduced in scope and is more specific regarding the purpose of the investment, i.e. that it is designed to have better control of the network.

SA Power Networks proposes to prioritise high bushfire risk areas, but states that this is separate to the bushfire mitigation strategies in the 2015-20 regulatory control period As a result, the number of substations that SA Power Networks proposes to install SCADA control and monitoring equipment is reduced from 203 to 75 substations.

Response to Strategic Augmentation: Network Control*:*

In the first instance, it is pleasing to see that SA Power Networks has revisited the proposal and reduced the overall scope. However, it is less clear why the costs of this program have increased from the original proposal even though the scope has been reduced. As the details of the revised business case are commercial-in-confidence, it is important that the AER investigate this apparent anomaly.

Recommendation:

The AER conduct an examination of the basis for SA Power Networks' costing of its network control plan in the revised regulatory proposal. The costs seem to have increased despite SA Power Networks' claim that there has been a reduction in the overall scope of the project.

There are two other general points:

- It seems reasonable and prudent in principle for SA Power Networks to continue to extend the SCADA system but it is less clear if this requires "special funding" as this appears to be just an extension of existing programs that are part of the 2010-15 cost base; and
- If SA Power Networks does extend SCADA and does so with a focus on high priority areas, then it is reasonable to expect commensurate reductions in other costs and improvements in reliability outcomes (such as SAIDI and SAIFI) for both MEDs and non-MEDs periods.

Irrespective of the AER "approving" a specific project expenditure, however, SA Power Networks is able to undertake the project if it sees a positive net benefit of rolling out the new technology. SA Power Networks has already identified what these benefits are likely to be:[100]

- Reduced visits to zone substations;
- Reduced number of customers without energy during high bushfire risk times;
- Reduced the number of minute without energy supply;
- Allow SA Power Networks to control when embedded generators are operating and switch them on/off at times of network constraints, thus reducing the need to augment the network; and
- Improved management of load to avoid outages from overloaded transformers.

All of these outcomes suggested by SA Power Networks will have positive benefits for SA Power Networks. Some will result in direct savings in opex and future capex, some will reduce GSL payments, and some will increase the likelihood of SA Power Networks being rewarded under the STPIS and EBSS incentive schemes.

At the end of the day, therefore, this is a business decision for SA Power Networks' management to make. However, the CCP2 does not accept that customers should fund reward payments under the incentive schemes for lowering costs and also fund the projects that assisted SA Power Networks to achieve these savings. If the costs of innovation are merely "pass through" costs, then the AER is not applying an incentive regime approach to regulation; it is conducting a rate case.

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[100] SA Power Networks, *Regulatory Proposal 2015-20*, October 2014, supporting document 20.69 (b), pp 15 – 24; cited in AER, *Preliminary Decision SA Power Networks distribution determination*, Attachment 6, p 6-72.

In addition, as stated in several places the AER is not approving projects, it is approving an overall amount of capex. It is up to SA Power Networks' management to establish priorities. If a project "stacks up", then SA Power Networks does not need special allowances or approvals to proceed.

SA Power Networks has also revised its proposal with respect to network monitoring. SA Power Networks' revised proposal is now limited to monitoring 125 non-SCADA connected HV sites using data loggers, for a total of $2.6 million. If the AER were to accept SA Power Networks' revised proposal for additional funding for SCADA on network substations in vulnerable areas, it makes sense to also allow the low cost monitoring on non-SCADA substations.

Recommendation:

The AER not accept SA Power Networks' proposal for additional funds for network monitoring. SA Power Network's already has an ongoing program of rolling out SCADA and the costs of continuing this roll-out should be captured in its previous expenditures

5.5 Non-Network Capex

5.5.1 Overview of AER's PD and SA Power Networks' revised proposal

SA Power Networks' initial proposal for non-network capex was $616 million ($2015)[101]. This represents a very significant increase in expenditure compared to 2010-15. The main driver of this change is the increase in capex for Information Technology (IT), although there are also increases in motor vehicles and buildings and property.

This is illustrated in Figure 5.3. In particular, SA Power Networks is proposing a step change in capex to support its IT plans.

In its PD, the AER approved some $370 million ($2015) for total non-network capex, around 40 per cent less than SA Power Networks' original proposal.

SA Power Networks' revised proposal for non-network capex is around $513 million ($2015). While this is $100 million less than its original proposal, SA Power Networks' revised proposal for non-network capex still represents a significant increase compared to actual expenditure in 2010-15.

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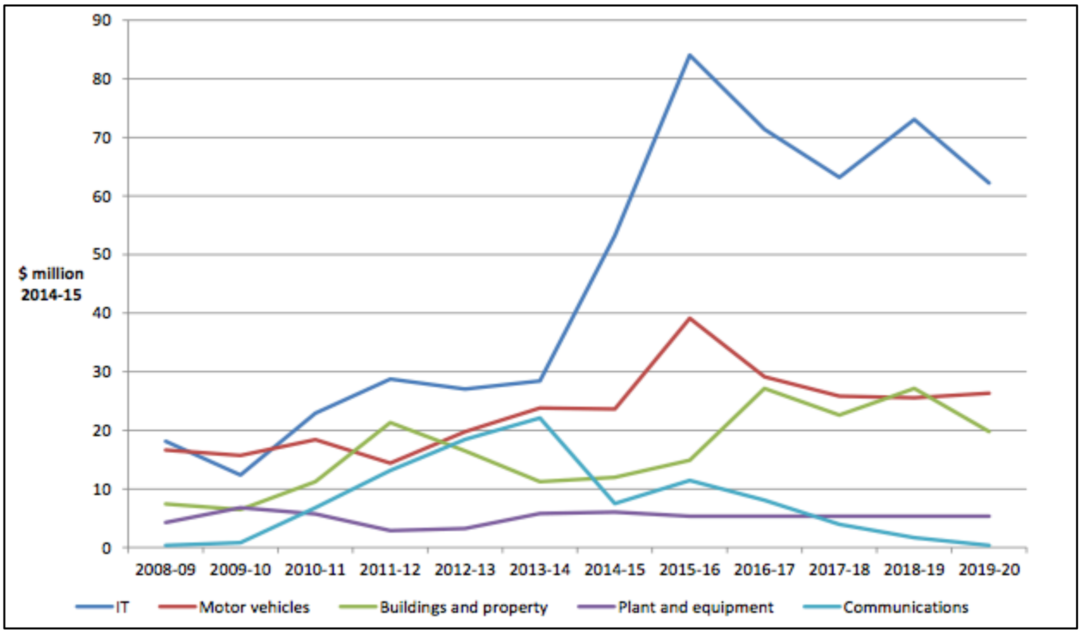
[101] SA Power Networks, *Revised Regulatory Proposal*, July 2015, Table 7.26, pp 140 – 141. Totals include a reduction to reflect negative superannuation changes of around -$48 million. The values are somewhat different than the values reported in the AER's PD.

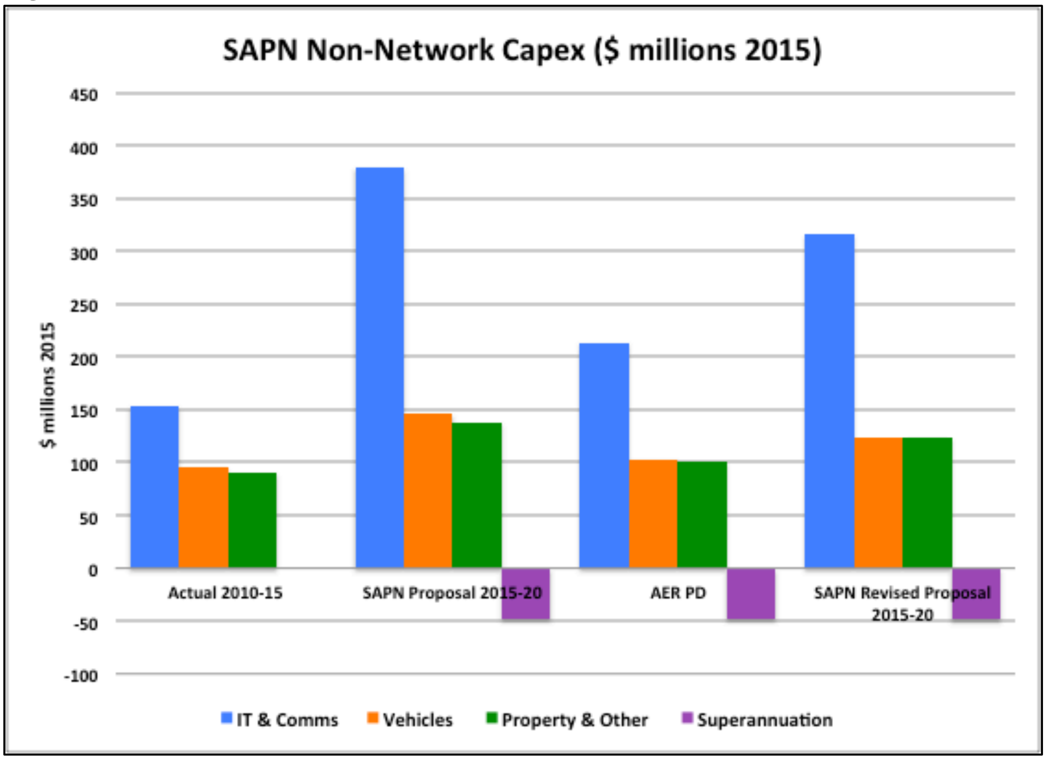
Figure 5.3 SA Power Networks' non-network capex by category ($ millions 2015) (SA Power Networks original proposal)



Source: AER, *Preliminary Decision SA Power Networks distribution determination*, Attachment 6, Figure B-15, p 6-112.

Figure 5.4 illustrates the change in each of the major components of non-network capex.

Figure 5.4: SA Power Networks' Non-Network Capex, Actual and Forecast



Source: SA Power Networks, *Regulatory Proposal*, October 2015, pp 231-249; SA Power Networks *Revised Regulatory Proposal*, July 2015, Table 7.26, pp 140-141, AER, *Preliminary Determination*, April 2015, Attachment 6, pp 6-109 – 112; CCP2 analysis. Notes: (a) 2010-15 figures are nominal dollars; (b) 2010-15 superannuation costs are not included but it is suggested they are much the same as 2015-20.

5.5.2 Information Technology Capex

5.5.2.1. AER PD and SA Power Networks Revised proposal for IT related capex

Figure 5.4 above demonstrates that the major component of SA Power Networks' non-network capex relates to expenditure on 'IT & communications' upgrades (excluding network communications such as SCADA). IT & communications capex is also the major driver of the increase in non-network capex between 2010-15 and 2015-20 in both the original and revised proposals.

In its original proposal, SA Power Networks sought a total IT expenditure of $354 million (plus $10 million for communications technology). The IT component was over 120 per cent greater than the actual/estimated expenditure in 2010-2015. In turn, the 2010-2015 expenditure was more than 100 per cent greater than 2005-2015 RCP.[102]

SA Power Networks' original proposal for 2015-20 included substantial expenditures ($182 million) on "non-recurrent" IT expenditure with 24 non-recurrent IT projects and associated "business change" capitalised expenditure.

SA Power Networks explained the need for such a large expansion of its IT capex as follows:[103]

> *What has become clear is that we need to move away from the incremental change to business processes (which has occurred over many years) to a more integrated 'end state' approach to data, systems, processes and people which is linked to service outcomes and business objectives. Our business processes are spread across multiple IT systems creating hurdles to delivering business requirements and responding to customer needs.*

The AER PD allowed an IT expenditure of $214 million, a reduction of some $140 million compared to SA Power Networks' original proposal. However, the total amount still exceeded actual expenditure in 2010-15 by some $50 million.

The AER, however, accepted SA Power Networks' proposed "recurrent" capex of $126 million ($2015). The AER allowed less than half the proposed "non-recurrent" capex (i.e. $88 million of the proposed $182 million non-recurrent IT capex). This figure for

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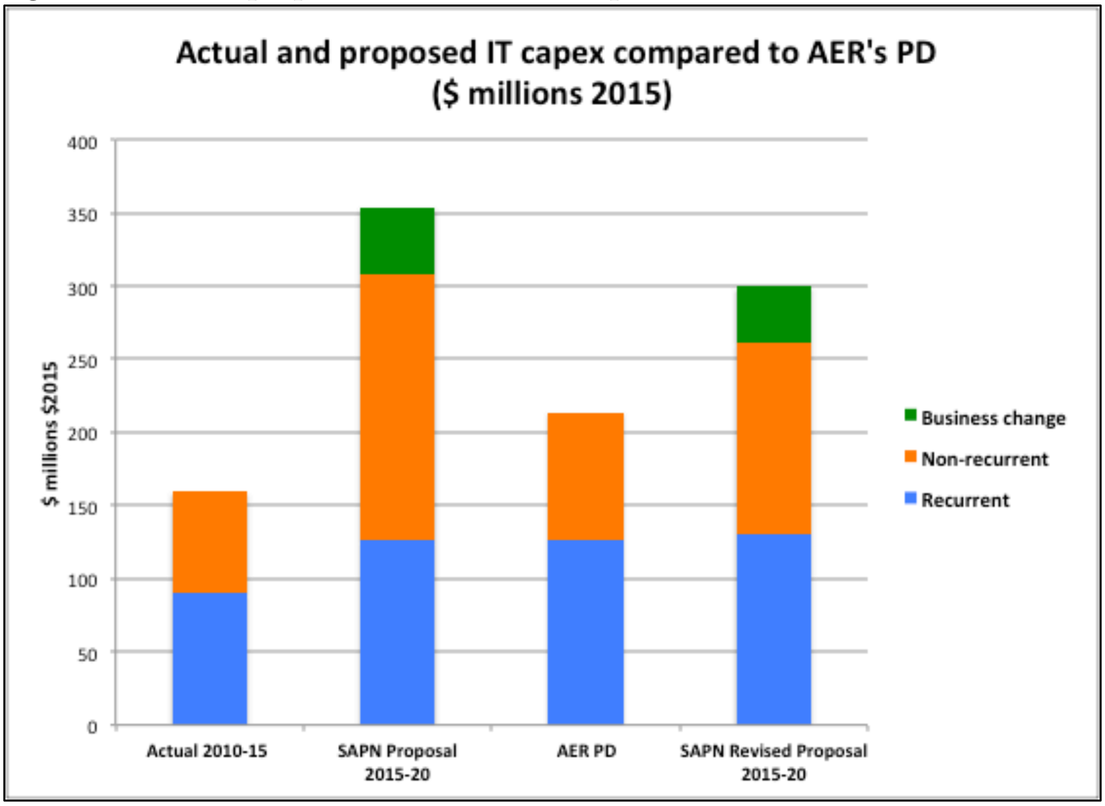
[102] AER, *South Australia, Draft distribution determination, 2010-11 to 2014-15*, November, 2009. p 167. Numbers will not reconcile completely with other numbers sourced from SA Power Networks Revised Regulatory Proposal.

[103] SA Power Networks, *Regulatory Proposal 2015-2020*, October 2014, p 232.

non-recurrent capex is based on the average level of investment by SA Power Networks across 2013-14 and 2014-15.[104]

SA Power Networks' revised IT proposal of $300 million is still some 85 per cent more than its expenditure on IT in 2010-15. Of this $300 million, less than half (46 per cent) relates to recurrent expenditure. Non-recurrent expenditure and the associated business change costs totalling $169 million make up around 56 per cent of SA Power Networks' total revised IT expenditure plans. The changes are illustrated in Figure 5.5 below. SA Power Networks is still proposing a significant increase in both recurrent and non-recurrent expenditure compared to 2010-15 IT capex.

Figure 5.5: Actual, proposed and revised IT capex and the AER's PD



Source: SA Power Networks, Regulatory Proposal 2015-20, October 2014, Table 20.41, 20.42; SA Power Networks, *Revised Proposal 2015-20*, Table 7.26, p 140, AER, Preliminary Decision, p 6-114; CCP2 analysis. Note: The AER does not specifically identify business change costs for 2015-20. Actual 2010-15 business change costs are not specifically identified by SA Power Networks.

Given that the major differences in non-network capex relate to IT expenditure, CCP2's assessment will focus on this component as set out in Section 5.5.2.2 below.

5.5.2.2. Response to AER's PD and revised IT capex proposal

In our response to SA Power Networks' original 2015-20 regulatory proposal, CCP2 highlighted that SA Power Networks' proposed non-recurrent expenditure program was very high compared to past expenditures and there were significant risks

[104] AER, *SA Power Networks, Preliminary Determination*, April 2015, p 6-122.

concerning the timing, deliverability and cost impacts of undertaking such a large and complex proposal within a single RCP.

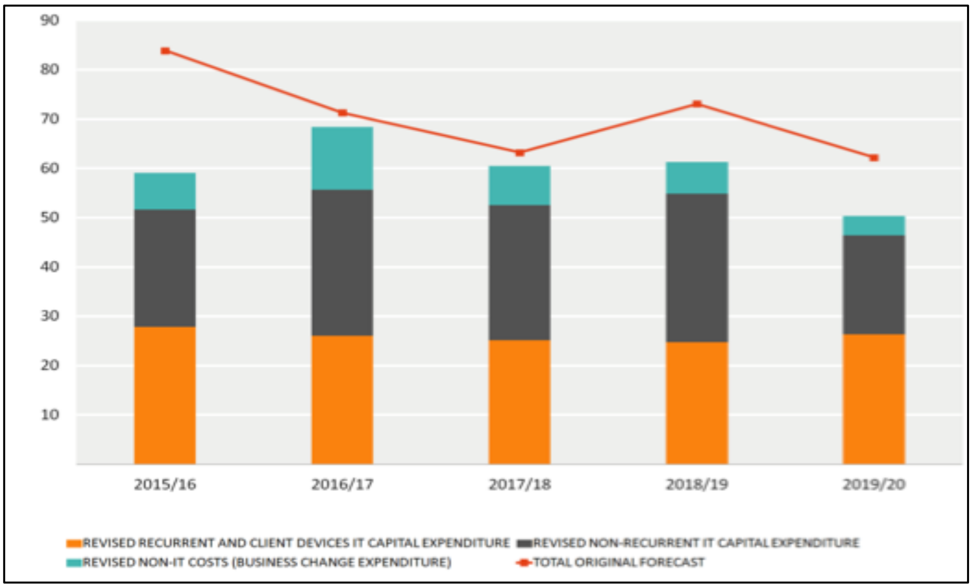
It was concerning that some of the expenditures were intended to meet regulatory and policy changes that were still in a state of flux while other IT capex related to SA Power Networks' proposed voluntary and accelerated roll out of "smart ready" meters, a policy that CCP2 did not support.

The AER expressed similar concerns and concluded after a detailed examination of each of the 24 projects that apart from the replacement of the customer information system, most projects were wholly or partly discretionary in nature. The AER considered its alternative forecast that included an average of $88 million per year for non-recurrent project was deliverable, prudent, efficient and justifiable.[105]

SA Power Networks has rejected the views of the AER and CCP2 regarding the capability risk. Nevertheless, SA Power Networks has made some important modifications to its IT plan in its revised proposal as illustrated in Figure 5.6 below. The changes include:

- prioritisation of IT initiatives;
- reduction in scope for 2015-20 regulatory control period;
- postponement of some activities to 2020-25 regulatory control period; and
- smoothing of capex within the 2015-20 regulatory control period.

Figure 5.6: Comparison between the revised and original IT capex forecasts



Source: SA Power Networks, *Revised Regulatory Proposal 2015-20*, July 2015, Figure 7.2, p 154.

CCP2 considers that SA Power Networks' revised proposal provides a more reasonable road map to introducing the necessary enhancements to its IT systems and processes.

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[105] Ibid, pp 6-121-6-122.

For instance, it is appropriate that SA Power Networks' overhaul of its suite of existing systems will now be undertaken over two RCPs rather than in a single five year period.

This will also assist SA Power Networks to better manage uncertainty around policy and market development issues. We note in particular a number of factors that may reduce the risk of the IT plan:

- Average annual expenditure of $60 million is within the most recent reported annual expenditure ($53 million $2015) and, therefore, efficient project and resource management will not be such a challenge;
- The smoothing of the IT annual capex plan across the 2015-20 RCP will allow more time for SA Power Networks to build up its IT and business change capacity more efficiently (the previous proposal had a very high front end expenditure requiring rapid expansion);
- The delay in peak IT expenditure until 2016-17 also provides time to develop more certainty on the various market rule changes around meter competition; [106]
- A number of more 'discretionary' projects are deferred to 2020-25. Again, this will reduce risk and provide more time to understand how the market evolves following the implementation of the full suite of Power of Choice policies.

Despite these improvements, there are risks in the implementation of such a complex process. The AER is requested to assess SA Power Networks' proposed changes to its IT plan to confirm that the proposed IT capex and the IT implementation plan are prudent, efficient and deliverable. If the AER approves capex for new IT systems then it is appropriate that consumers can reasonably expect the project to be delivered on time and that the projects funded for the 2015-20 RCP are not 'pushed out' into the next RCP.

Recommendation:

The AER review the risks and timing of SA Power Networks' revised IT plan to ensure that it is prudent, efficient and deliverable, including the additional labour and contractor costs.

Nevertheless, if the risks are manageable, there appears to be some merit in some of the components of SA Power Networks' revised proposal.

However, across most DNSPs there is an absence of any links between the ex ante claimed benefits and the actual benefits delivered to consumers on completion of the IT projects. We expect that in future there should be much greater transparency on these

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[106] CCP2 notes, for instance, that the AEMC has already recently revised its timetable for publishing final rule changes for the Competition in Metering and Related Services from July to November 2015. The implementation date has also been revised to 1 December 2017. The AEMC states: "The extension is necessary to consider complex issues …around the details of implementing a competitive framework for metering" (AEMC, "Information Sheet, Extension of time for final rule on provision of metering services", 30 July 2015.)

relationships. In particular, it is important that there is seeks much greater transparency on the expected and actual benefit realisation from SA Power Networks' IT investment given the significant increases over the previous IT expenditures.

For instance, CCP2 would expect that a new CIS system and related updates to other systems such as the CRM, would deliver quantifiable benefits and cost savings to consumers within this RCP (and beyond). This is because the new CIS and related systems will be replacing many of the manual processes that SA Power Networks has highlighted throughout this section of its proposal.

Recommendation:

In its FD, the AER consider whether the potential savings in opex that should arise in this RCP with the replacement of SA Power Networks' basic CIS and CRM IT are adequately captured in the opex allowance.

In similar vein, CCP2 would expect to see a careful review of SA Power Networks' "recurrent capex expenditure" as these costs should decline as new, more efficient IT systems replace the older systems.

CCP2 does not see that outcome in SA Power Networks' proposal; rather there is an overall average increase in recurrent expenditure in real dollar terms between 2010-15 (average $18 million per year) and 2015-20 (average $26 million per year).

We do not consider it to be credible that recurrent capex expenditure would increase to this extent given the claimed benefits of the new IT investments.

Recommendation:

The AER review its assumption that recurrent IT capex is allowed if it is consistent with 2010-15 recurrent capex. Recurrent capex should decline as a result of the update of key systems and business processes.

As a final comment on SA Power Networks' revised IT proposal, CCP2 highlights the comments in our original submission, namely that we would expect some synergies in SA Power Networks' IT costing because of its corporate links to the two Victorian DNSPs, CitiPower and Powercor.[107] Both the Victorian DNSPs have established systems to manage interval meter data and we are somewhat surprised to see no reference in SA Power Networks' proposals or IT plan to the opportunities for SA Power Networks to gain efficiencies from these experiences and capabilities.

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[107] Consumer Challenge Panel 2, *Submission on SA Power Networks Regulatory Proposal*, January 2015, Section 9.

In comparison, CCP2 notes that in the proposal for the 2010-15 RCP, the AER's consultant (PB) highlighted the efficiencies that ETSA Utilities gained by sharing IT development costs with CitiPower and Powercor. The AER stated:[108]

> *PB found that the replacement FRC systems are required due to discontinued vendor systems supporting the existing IT platform and that ETSA Utilities' cost sharing with CitiPower and PowerCor is an efficient way to establish replacement systems.*

The report by PB suggests that SA Power Networks already has access to shared systems and shared costs with CitiPower and Powercor.

CCP2 also understands that CitiPower and Powercor are also updating their aging CIS-OV platform and in their recent public regulatory proposals they have included a proposal to move to the SAP ISU billing system together with a cloud-based CRM managed by Salesforce. They stated this approach provides a sound platform to efficiently meet new reporting and customer requirements.[109]

Of course, it would be expected that SA Power Networks would share a reasonable proportion of such costs but as all three parties move off the existing CIS-OV platform it seems sensible to expect that there would be significant synergies and that overall costs of replacement of CIS OV would be shared across the three businesses as were the costs of the replacement FRC systems.

Therefore, it would be helpful if the AER considers the possible savings from shared costs and discuss with SA Power Networks whether the new CIS and CRM costs of $67.7 million ($2015) are a reasonable reflection of actual costs to SA Power Networks for an efficient CRM.[110]

CCP2 also requests that the AER give consideration to how the capabilities of the new CIS and CRM systems will reduce SA Power Networks' need for additional funding for managing new tariffs etc. That is, consumers need to be assured that there is no double counting of costs and any subsequent pass through applications includes an assessment of the opportunity for SA Power Networks to have built in the necessary capabilities at the start.

In particular, modern utility CIS, CRM and other billing systems, including the SAP platform, are built to provide flexibility to handle different tariffs structures. SA Power Networks should ensure that it includes such requirements in its tender documents. The incremental costs of providing this capability are likely be relatively small given international trends in network pricing.

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108 AER, *South Australia, Draft distribution determination, 2010-11 to 2014-15*, November, 2009, p 169.

109 See for instance, CitiPower, *2016-2020 Price Reset*, Appendix E, Capital Expenditure, April 2015, p 146.

110 SA Power Networks, *Revised Regulatory Proposal*, July 2015, Table 7.28, p 155.

Recommendations:

The AER consider opportunities for savings in IT capex given SA Power Networks corporate links to two Victorian DNSPs. If it does, then CCP2 requests that the AER consider how these savings might be taken into account in its determination

The AER clarify if the proposed new CIS and CRM systems will have built-in capability to manage new tariff designs, larger data sets and competition in metering, thus avoiding high costs post 2017.

5.6 Capex Input Cost Escalations

In its original proposal, SA Power Networks proposed a total real cost escalation of $98.1 million for capex in the 2015-20 RCP. The real cost escalation proposal was based on SA Power Networks' forecasts of real cost increases in labour costs, contract services, materials and land. Of these cost categories, labour and contract costs made up the majority of the total costs and the cost escalation.

The AER did not accept SA Power Networks' forecast of real cost escalations in labour costs or materials costs. The AER substituted SA Power Networks' forecast of labour costs with a forecast from Deloittes Access Economics (DAE) that was based on a forecast of changes in the Electricity Gas Water and Waste (EGWW) wage price index (WPI).

SA Power Networks accepted the AER's forecast of materials cost escalation. However, SA Power Networks did not accept the AER's forecast of labour costs. In its revised proposal, SA Power Networks adopted the same approach as it did in its original proposal, namely:

- Use the labour price rise in its Enterprise Agreement (EA) for 2014-16 of 1.66 per cent in real terms for the first two years of the forecast period; and
- Extrapolate benchmarked EA outcomes of 1.77 per cent in real terms from similar businesses based on analysis from Frontier Economics of privately owned transmission and distribution service providers in Australia.[111]

The AER's approach appears the preferable one, although this is a difficult areas for forecasting. . It provides the appropriate incentives for labour productivity and is consistent with the most recent trends in wages growth that are at their lowest historical rates across all industries

Further discussion on input cost escalations is included in Section 6 below.

Recommendation:

The AER retain its forecast of escalation of input costs for capex.

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[111] SA Power Networks, *Revised Regulatory Proposal*, 2015-20, p. 182.

5.7 Summary CAPEX Table for

	Parameter	AER Preliminary Determination	SAPN's revised proposal	Comments
Replacement Capex	Replacement	Reject SAPN's original proposal, but still approves amount significantly greater than 2010-15 actual	Disagree with AER, aging network and condition assessment result in obligation to increase replacement	AER's allowance very generous. Provides SAPN with sufficient funds to focus on HBRA & remote supply
Augmentation Capex	Demand Driven	Accepts SAPN's core demand growth capital & quality of supply. Rejects 2 way network	Accepts AER's PD	AER's decision does not reflect low demand, little network size growth & excess capacity
	Safety	Accepts SAPN's core program but not additional bushfire and road safety programs	Disagree with AER based on reg. requirements & CE research. Dropped road safety issue	Agree with AER; SAPN's proposals go beyond reg. requirements. AER would be displacing Govt et all decision making & funding options. Back up protection has value
	Reliability	AER accepted core maintaining reliability, but rejected other parts of SAPN's expanded program,	Disagree with AER based on reg. requirements & CE research, which supports hardening	Agree largely with AER. SAPN's current performance meets standards & SAPN overstated reg

		SAPN already compliant with reliability standards	network & addressing low reliability feeder areas.	requirements. Up to SAPN to prioritise re hardening etc
	Strategic	AER accepts Kangaroo Island (KI) but not additional network control & monitoring installations	SAPN accepts AER's position on KI, but does not accept rejection of additional network control, RIN reporting and LV network monitoring	Agree largely with AER. However, KI project could be "contingent project", need to conduct RIT-D and explore other options; life cycle costs not clear, additional back-up still required and risk of redundancy if solar etc gets stronger
	Environmental	AER accepts SAPN's proposal	Accept	No comment
	Other (PLEC)	AER accepts SAPN's proposal	Accept	Agree
Non-Network Capex	**IT**	AER rejected SAPN's 5total project but accepted replacement of core IT systems (CIS, CRM et al)	SAPN reject AER's position but reduces scope of IT change program	Largely agree with AER but would like more transparency on cost/benefit & when this benefit is shared with consumers. Query if opportunity to reduce "recurrent" IT capex once new systems in place.
	Communications	AER does not	SAPN rejects	No comment

		accept SAPN's proposal	AER's position	
	Vehicles, Property and other	AER does not accept all vehicles (new fleet) & property	SAPN rejects most of AER's position	No comment
	Capex Input Costs	AER does not accept SAPN's labour & materials costs	SAPN agrees on materials costs but not on labour	Agree largely with AER position

6 Forecast Operating Costs (Opex)

6.1 Overview

The forecast opex has a direct impact on SA Power Networks' revenue allowance in two ways. First, the opex forecast is a key component of the building block assessment of the total revenue allowance. Second, the expenditures in the 2015-20 period (specifically year 2018-19) will form the basis of the AER's assessment of the opex allowance for 2020-25.[112]

The opex allowance also has a close interdependency with the capex allowance. At a high level, for instance, it would be expected that higher capex in one period will result in savings in opex in the following regulatory periods (as discussed above). This is because assets that have been replaced or augmented should require less maintenance and manual operation. Similarly, the enhanced IT and communication systems should lead to general improvements in company opex productivity. If they do not, then one must question the business case that underpinned the IT plan.

However, although the AER allowed a considerable increase in capex investment in the 2010-15 RCP, there is no evidence provided by SA Power Networks that the benefits of this previous investment have been captured in the opex forecast for 2015-20.

Similarly, despite further increases in capex in 2015-20, there are no commensurate savings identified in opex over the regulatory control period with the exception of some relatively small savings in opex from the proposed IT investment.

However, in its regulatory proposals, SA Power Networks suggests that increases in capex require increases in opex in order to manage the additional capex. This would be more understandable if the capex was largely related to growth in the network (e.g. there are more customers to manage).

In this instance, however, the additional capex is not related to growth in the network as the largest components of capex arise from non-demand related replacement capex[113] and non-system capex. It is not at all clear why replacing assets and updating IT systems should lead to increases in opex. Rather, it is expected that labour, overheads and materials associated with this type of capex would be capitalised and, from an ongoing point of view, there should be additional savings in opex.

In the absence of transparency on costs and benefits across regulatory periods, it is difficult for consumers to unpick these various competing trends.

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[112] That is, assuming the AER continues with the base step trend (revealed cost) approach to assessing opex.

[113] We include in this capex associated with safety and reliability, which SA Power Networks categorises as augmentation projects.

However, it is possible to focus on overall trends in total opex costs and opex efficiency, particularly as both SA Power Networks and the AER apply the "revealed cost" (or base-step-trend) approach to assessing the forecast opex in line with the AER's Expenditure Forecast Assessment Guideline.[114]

In the absence of changes to the relevant regulatory regime and operating environment (above the background rate of change) then generally, there should be no reason to expect increases in operating costs (in real dollar terms) and many reasons to expect reductions in operating costs per customer including efficiencies gained from the capex investments as suggested above.

In making an assessment of the opex proposal it is therefore essential to differentiate between:

- Opex that is necessary to efficiently and prudently maintain a reliable, quality and safe network and network services consistent with the regulatory obligations and a reasonable forecast of demand; and
- Opex that provides an additional level of service over and above that delivered in accordance with (a).

This does not mean that SA Power Networks is prevented from providing additional services or introducing new technology such as smarter grids; that is a decision for its SA Power Networks' Board and management based on an assessment of the costs and benefits to SA Power Networks. Nor does it stop SA Power Networks reprioritising its expenditures to meet changing customer priorities, providing it continues to meet its regulatory obligations and meet demand for its network services.

It does mean, however, that the AER cannot provide a regulatory allowance beyond that required to efficiently meet electricity demand and satisfy all relevant regulatory and legal obligations.

The response in this paper to SA Power Networks' initial and revised proposals for opex allowances therefore includes two distinct elements.

First, it is important to acknowledge SA Power Networks' relative efficiency and prudency in its historical opex. However, there is also a marked downward trend in opex productivity of some 4.8 per cent per year[115] from 2006 and the reasons for such a significant decline are not readily apparent.

Second, we express our concern with SA Power Networks' proposed substantial increases in real dollar opex for 2015-20 above its historical trend. We consider the significant increases in the forecast opex in SA Power Networks' revised regulatory proposal are neither efficient nor prudent in the current circumstances and will lead to

[114] AER, *Expenditure Forecast Assessment Guideline*, November 2013. Further details are provided in AER, *Explanatory Statement, Expenditure Forecast Assessment Guideline*, November 2013.
[115] See Table 6.1.

further and accelerating decline in opex (and total factor) productivity in an era of low growth in the output measures of customer numbers, ratcheted peak demand and circuit line length.

Nor is the proposal to increase opex an effective response to the challenges of lower demand growth. In the face of these challenges, a business would not normally increase its underlying operational costs in the way proposed by SA Power Networks. Rather it would seek to maximise the efficiency of its current operations and reduce its prices while maintaining service levels.

The assessment set out in the following sections will focus on the AER's PD and on SA Power Networks' revised opex proposal in response to the PD.

Many of these issues were extensively canvassed in CCP2's response to SA Power Networks' original proposal and we refer the AER to this submission as further evidence of CCP2's views. The submission to the AER by the SA Government (January 2015) also provides some insight into the jurisdictional regulatory requirements that SA Power Networks operates under.

6.2 Review of SA Power Networks' Opex Proposal

SA Power Networks' original opex proposal was for an opex allowance of $1,527 million ($2015)[116] for the 2015-20 RCP. This represented a very substantial increase in opex compared to the actual opex in the previous RCP (2010-15) of some $1,100.[117]

The AER's PD reduced the proposed opex amount by some 20 per cent. The AER largely accepted SA Power Networks' proposed base year costs (2013-14) on the basis that the opex in that year "does not appear to be materially inefficient"[118] but rejected SA Power Networks rate of change and step change proposals.

In its revised proposal, SA Power Networks accepted the AER's base year costing. However, SA Power Networks did not accept the AER's approach to assessing step changes and rate of change. The AER had allowed a total of $30 million ($2015) over the RCP for step changes and rate of change. SAPN's revised proposal includes an amount of $227 million ($2015).

As a result, SA Power Networks' revised proposal is **only 7 per cent less than its original proposal** and remains significantly above the AER's PD (some 17 per cent greater).

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116 Total excludes debt raising costs.

117 From SA Power Networks, *Regulatory Proposal 2015-20*, October 2014, p 252. The figure quoted for 2010-15 is in nominal dollars.

118 AER, *SA Power Networks, Preliminary Determination*, April 2015, Attachment 7, p 7- 21.

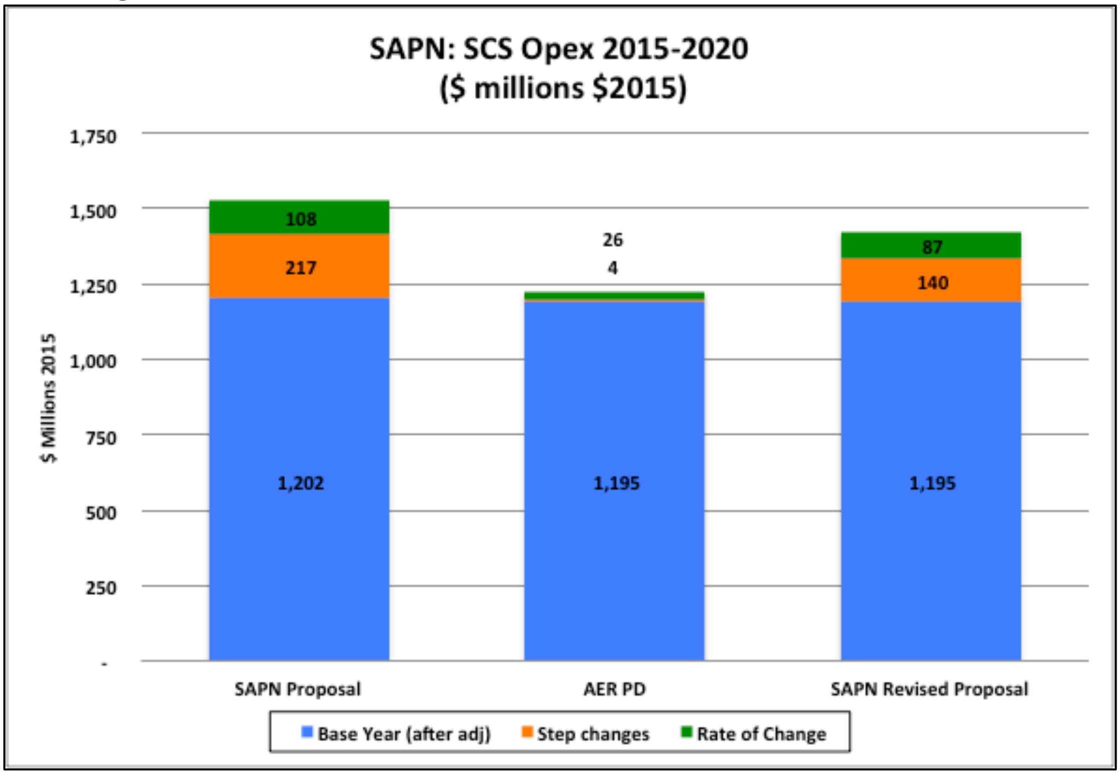
Figure 6.1 below illustrates the differences between SA Power Networks' original proposal, the AER's PD and SA Power Networks' revised proposal.

Recommendation:

The AER not accept the overall opex proposed by SA Power Networks in its revised proposal.

The AER's base year allowance may be too high, but the AER's decision on rate of change and step changes is in large part a satisfactory reflection of the approach set out in the Forecast Expenditure Assessment Guideline.

Figure 6.1: SA Power Networks' Opex Proposals and AER's PD for 2015-2020 excluding debt costs ($ million, 2015)



Source: SA Power Networks, *Revised Regulatory Proposal 2015-20*, Tables 8.1, 8.4 & 8.5. Excludes debt raising costs

6.3 Assessment of the Base Year Opex

SA Power Networks and the AER agree that 2013-14 should be the base year for the purposes of assessing the forecast opex.

6.3.1 Summary of AER's PD and SA Power Networks 's revised proposal

The AER concludes that SA Power Networks' base year 2013-14 "does not appear to be materially inefficient"[119]. This conclusion is based on the results of AER's benchmarking analysis and the AER's review of SA Power Networks' own benchmarking studies.

The AER places most reliance on the benchmarking study conducted by Economic Insights (EI). The EI study has a focus on the assessment of overall multilateral total factor productivity (MTFP) and on opex multilateral partial factor productivity (MPFP). EI's analysis takes into account differences in customer numbers, ratcheted maximum demand and circuit line length between DNSPs in assessing the efficiency rating of each DNSP in the NEM.

Separately to the EI analysis, the AER includes allowance for a number of "environmental" factors that it claims impact differentially on the costs of various DNSPs.

The AER also places some reliance on its annual benchmarking report and on historical expenditure trends.

Across these various measures, SA Power Networks is found to be amongst the most efficient of the 13 DNSPs in the study. SA Power Networks' own benchmarking research confirms this position.[120]

The AER does note that although SA Power Networks performs well against its peers, its operating expenditures have increased significantly across the benchmarking period used by EI (2006 to 2013). The AER states that: "in real terms, SA Power Networks' opex in 2012-13 is 31 per cent higher than the average over the benchmarking period".[121]

However, the AER also concluded that most DNSPs saw a decline in MTFP and MPFP over the 2006-2013 period. Despite SA Power Networks' opex MPFP falling over the period, it remained amongst the five most efficient networks, although the gap had narrowed between the more efficient and most of the less efficient DNSPs.

This outcome, together with the fact that SA Power Networks has been subject to an opex incentive scheme leads the AER to conclude that SA Power Networks' base opex "is not materially inefficient", despite the decline in the 2012-13 performance relative to the average of SA Power Networks' performance over 2006-2013.[122]

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[119] AER, *SA Power Networks Preliminary Determination*, April 2015, Attachment 7, p 7-21.

[120] See for example, SA Power Networks, *Regulatory Proposal 2015-20,* October 2014, Figure 21.4, p 254 and Attachment 4.1 to the proposal.

[121] AER, *Preliminary decision SA Power Networks distribution determination 2015-20,* Attachment 7, p 7-35.

[122] The EI assessment of comparative efficiency is based on the average annual efficiency over the period, approximately equivalent to the mid-point in the series.

The AER also made a number of minor adjustments to the base year including adjustments for self-insurance, reclassification of metering services and demand management innovation allowance.

SA Power Networks is concerned that the AER defines its base year performance as "not materially inefficient". SA Power Networks claims this fails to recognise that SA Power Networks has been benchmarked as one of the most efficient distributors in the NEM and considerably more efficient than the AER's revised benchmark frontier. SA Power Networks states:[123]

> *Had an allowance for environment factors been applied, SA Power Networks would clearly be at the efficient frontier.*

Not withstanding these concerns, SA Power Networks has accepted the AER's adjustment of the base year costs.

6.3.2 Response to AER's PD and SA Power Networks' revised proposal for the base year

A review of the EI benchmarking research confirms that on an historical basis (2006-2013), SA Power Networks is clearly amongst the more efficiently performing group of DNSPs on both MTFP and the opex specific MPFP measures.

However, significant downward trend in SA Power Networks' performance on the opex efficiency measures such as the MPFP is concerning. This point is recognised by the AER who noted that the SA Power Networks' opex MPFP score by 2012-13 was 31 per cent higher (worse) in real terms than its average opex over the average score in the 2006-2013 period.[124]

Figure 6.2 below illustrates this decline in observed MPFP for SA Power Networks.

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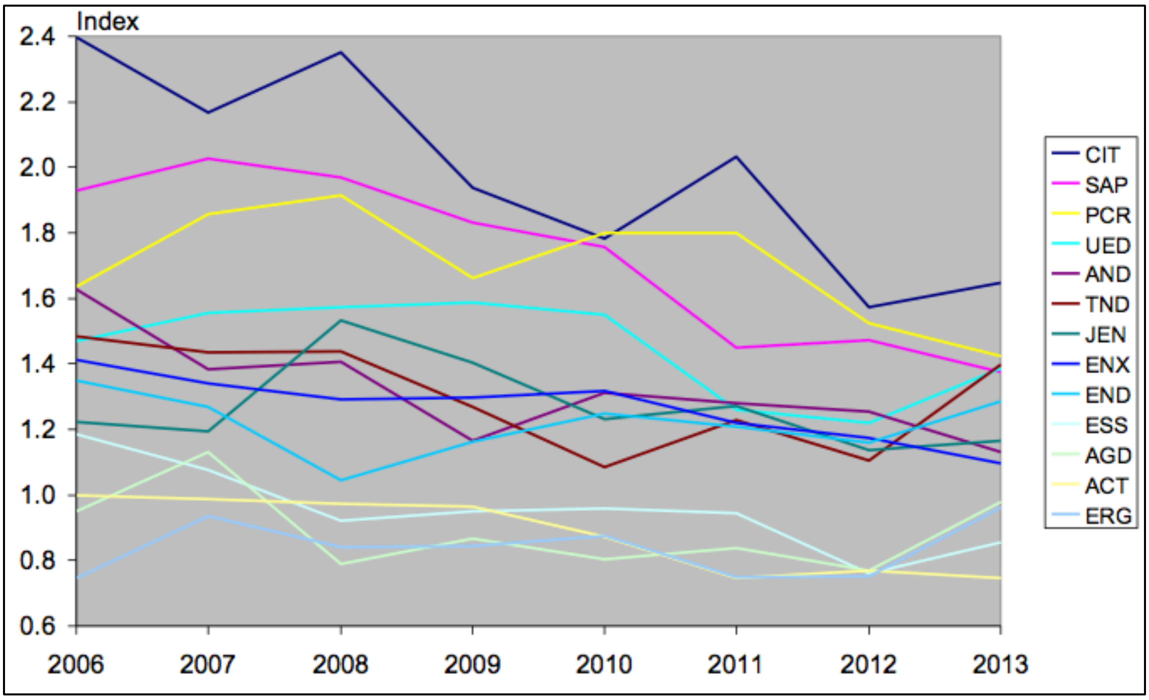
[123] SA Power Networks, *Revised Regulatory Proposal 2015-20,* July 2015, p 196. The AER applied a number of "environmental factors" that had the effect of shifting the efficient frontier to a lower figure. SA Power Networks is correct in stating that had this been applied to the companies above the original frontier there would be further adjustments to the order of efficiency at the top end. However, it is difficult to say without further analysis how these top five businesses would have moved relative to each other as all the five DNSPs would be affected by adjustments due to environmental factors. For the record, the CCP2 does not support the AER's process of adjustment for environmental factors as applied in the recent NSW and ACT DNSPs' Final Determinations.

[124] AER, Preliminary Decision, SA Power Networks distribution determination, Attachment 7, p 7-35

Figure 6.2: Opex multilateral partial factor productivity indexes, 2006-2013



Source: Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November 2014, p 20.

Table 6.1 below also illustrates the different trends in efficiency and, in particular, the relatively high rate of decline in MPFP for SA Power Networks.

The table sets out the average opex MPFP for the top three and the bottom three networks along with the average annual change in MPFP over the period 2006 to 2013 based on the EI benchmarking study data. Such a decline raises questions about he effectiveness of the efficiency scheme (EBSS) in driving more efficient performance over time.

Table 6.1: Annual rate of change in MPFP for high and low efficiency DNSPs

Ranking by MPFP index score	DNSP	Average opex MPFP Score 2006-13	Average Annual % change in MPFP 2006-13
1	CitiPower	1.986	-5.3%
2	SA Power Network	1.726	-4.84%
3	Powercor	1.702	-2.01%
11	Ausgrid	0.891	0.46%
12	ACT	0.883	-4.16%
13	Ergon	0.838	3.62%

Source: Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November 2014, Table 4.1, p 20.

It is certainly not easy to understand why there are such significant declines in MPFP, particularly for the CitiPower and SA Power Network. For example, CitiPower has the highest customer density while SA Power Network has one of the lowest so density is not a factor. SA Power Network had higher vegetation clearance costs from 2011, but the issues faced by SA Power Network were common across networks such as Powercor which experienced much the same swing from very low to very high rainfall and subsequent impact on vegetation growth rates. Moreover, SA Power Networks has enjoyed a relatively stable regulatory environment.

SA Power Networks also mentions that it is more difficult to extract efficiencies when a firm is operating closer to the efficient frontier. However, this not a particularly relevant argument, as it does not explain the observed decline in SA Power Networks' productivity outcomes.

Overall, there do not appear to be any satisfactory reasons provided by EI, the AER or SA Power Networks to explain the extent of the decline in the MPFP (-4.84% per annum over 2006-2013). This in turn suggests that the 2013-14 year does not represent an efficient base year relative to SA Power Network's own "best" performance. This is perhaps why the AER concludes that SA Power Networks' base year is "not materially inefficient"? This is a conservative conclusion given the data provided above.

More importantly, the AER's conservative benchmarking approach, locks in the recent increases in opex and the associated decline in SA Power Networks' MPFP (and in MTFP), by using the end point of the benchmarking analysis as the base year to be carried forward into the 2015-20 RCP.[125]

From the perspective of consumers' long-term interests the AERs conclusions on the base year and its impact on 2015-20 RCP (and beyond) are not satisfactory. Moreover, as the reasons for the decline are not fully understood, it is not possible to know what factors need to be taken into account when assessing the need for future changes in the opex allowance, such as a negative step change allowance.

For example, if vegetation clearance costs increased as a result of the ending of the drought and heavy rains in 2011-2013[126], what adjustments should be made to the base year (2013-14) now that period of rapid vegetation growth has come to an end. And if there is no adjustment to the base year, should there be a negative step change for vegetation management expenditure for the forecast years?

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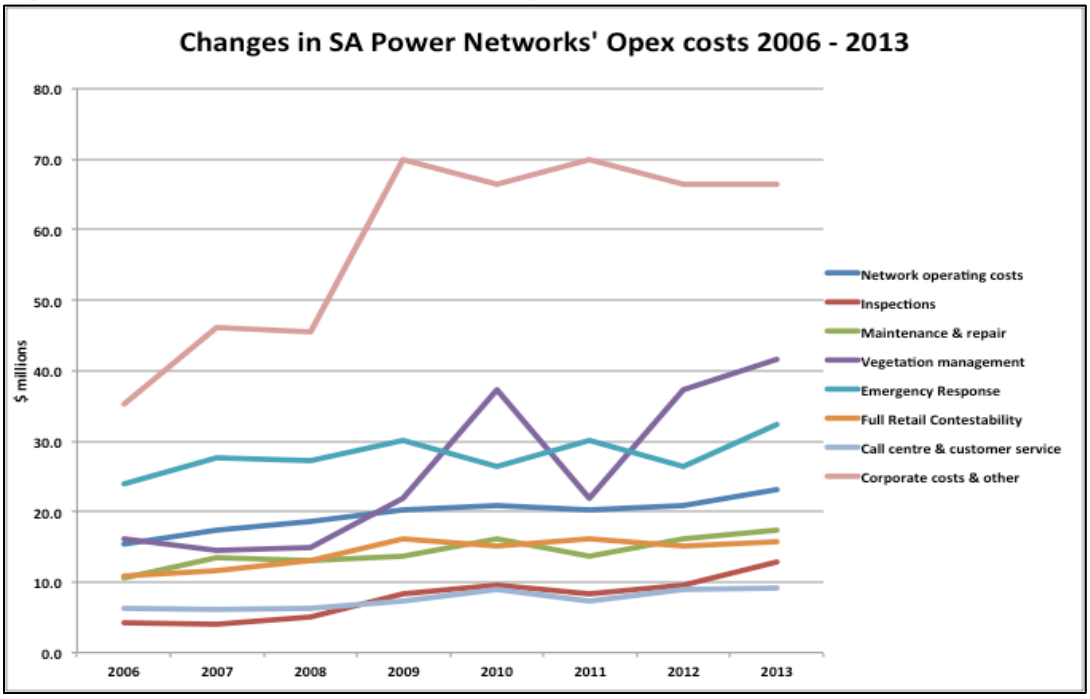
[125] A negative MPFP growth factor means that opex is increasing at a level that cannot be explained by changes in customer numbers, line length or ratcheted peak demand (the benchmark model inputs). In addition, the benchmarking model would predict the 2015-16 year on the basis of a decline in productivity. The AER, on advice from EI, has decided that it would not use a negative productivity to forecast future opex. However, the approach still 'embeds' the lower observed productivity at the end of 2006-2013 into the forecast period.

[126] While the AER's revenue pass through for increased vegetation costs affected prices in 2013-14 and 2014-15, SA Power Networks incurred the majority of the additional costs in the prior years.

Figure 6.3 illustrates the trends in each main category of opex for the period 2006 to 2013.

Figure 6.3: Historical trends in operating costs (2006-13)



Source: SA Power Networks, Economic Benchmarking Consolidated 2006-2013, "3.Opex". CCP2 analysis. Note: The "Corporate costs & other" category includes GSL and DM expenditures

It is not clear why the "Corporate cost and other" opex has grown so significantly after 2010. If it is a change in capitalisation approach, then we would have expected to see a commensurate reduction in capex over the same period. This reduction is not evident and it would be useful for the AER provide a clear explanation in its FD of this growth in corporate costs and whether this should influence its view that SA Power Networks' 2013-14 opex is the most appropriate efficient base for forecasting future opex.

Recommendation:

The AER investigate and explain in its FD why SA Power Networks' Corporate and other cost category has grown so significantly since 2010, before it accepts 2013-14 as an efficient base year

Figure 6.3 also demonstrates the rapid expansion in vegetation management costs and it is expected that the higher costs will be also reflected in the 2013-14 base year. The issue of SA Power Networks' vegetation management cost step change forecast will be discussed in some detail in section 6.5.3.3.

However, the following statement by the AER in its PD is relevant to the assessment of the base year:[127]

> *We also approved a $35.5 million ($2009-10) step change for SA Power Networks' vegetation clearance pass through as a result of changing weather conditions.* [i.e. higher vegetation growth rates]
>
> *If we used historical productivity to set forecast productivity, this would incorporate the effect of past step changes which as shown above have negatively impact on measured opex productivity. We do not consider past step changes should affect forecast productivity*

It is interesting that the AER recognises that the pass through costs for vegetation management (in this instance) has contributed to a decline in productivity over 2006 - 2013. The AER also recognises that the decline in productivity caused by the pass through event should not be recognised as a factor in the forecast of opex as it is temporary in nature.

The same logic should be applied to the AER's assessment of the efficiency of the base year 2013-14. That is, 2013-14 includes a component of the pass through costs for vegetation management. As this is a temporary factor, the costs arising from the pass through vegetation event should be removed from the base year costs

Recommendation:

The AER re-examine its assumption that the actual costs in 2013-14 reflect efficient costs for the purposes of forecasting future costs, particularly given the decline in productivity observed over 2006 -13.

6.4 Opex Rate of Change

This section considers the forecasts of rate of change in output, prices and productivity. The rate of change is applied to each year and captures changes in the costs of inputs such as labour and materials and output in terms of growth in customer numbers, ratcheted peak demand and line length.

6.4.1 Summary of AER's PD and SA Power Networks 's revised proposal

SA Power Networks' original proposal included a total of $108 million ($2015) costs to account for changes in outputs and in prices. It did not include a productivity growth factor that measures the expected shift in the efficiency frontier for an efficient and prudent service provider in the distribution industry.[128]

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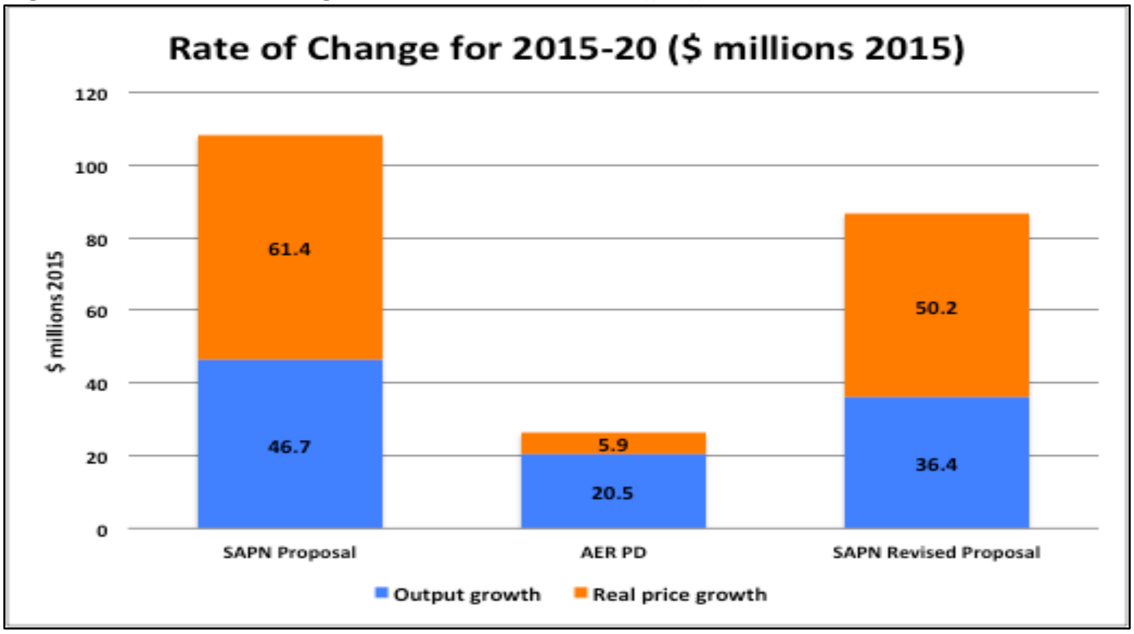
[127] AER, *Preliminary decision SA Power Networks distribution* determination 2015-20, Attachment 7, p 7-66.

[128] AER, *SA Power Networks Preliminary Determination, 2015-20*, Attachment 7, p 7-47.

The AER accepted SA Power Networks' proposed zero value for productivity growth. However, the AER rejected the two other factors of output growth and price growth in SA Power Networks' original proposal. The AER PD allowed a total of $26 million ($2015) for rate of change costs, as illustrated in Figure 6.4 below.

Figure 6.4: Rate of Change SA Power Networks' proposals and AER PD



Source: SA Power Networks, *Revised Regulatory Proposal, 2015-20*, Table 8.5, p 194; CCP2 analysis.

In its revised proposal, SA Power Networks reduced its total rate of change (including step changes) by some 20 per cent compared to its initial proposal, to a total of $87 million ($2015). However, it is still considerably greater than the AER's PD.

The following sections consider each rate of change component, viz:

- output growth;
- price growth; and
- productivity growth.

6.4.1.1. Output growth

In the first instance, the AER did not accept SA Power Networks' proposed output growth measures and substituted these measures with the measures identified by EI as significant explanatory variables being customer numbers, circuit line length and ratcheted peak demand. The AER's approach is preferable in that it ensures there is a conceptual and measurement link between the historical efficiency analysis by EI and the forecast opex.

Overall, the AER's allowance for output growth ($21 million) was less than half the output growth rate proposed by SA Power Networks' in the initial proposal of $48 million.

In the revised proposal, SA Power Networks accepted that output growth should be measured on the three factors in the EI model; customer growth, circuit line length and a maximum demand/capacity measure.

However, SA Power Networks disputes the AER's use of ratcheted maximum demand for forecasting capacity requirements in the opex forecast model. Instead, SA Power Networks has used a measure based on distribution transformer and substation capacity growth forecasts (as set out in their Reset RIN).

SA Power Networks claims that their measure of demand better captures the impact of "spatial increase in network capacity". SA Power Networks states that the AER has accepted the forecast of demand and demand related capex, so consistency requires that the AER uses a capacity based asset measure rather than a demand based measure such as ratcheted maximum demand.[129] SA Power Networks explains its position as follows:[130]

> *That is, under the existing output measures* [specifically, ratcheted maximum demand] *no increase in operating allowances will be provided for the maintenance and operation of the increase in network capacity that must be installed to meet demand and that has been accepted as efficient in the AER's preliminary decision on capital expenditure allowances.*

As a result, SA Power Networks' is still proposing an allowance for output growth of some $36 million, which is around 78 per cent greater than the AER's allowance. SA Power Networks concludes as follows:[131]

> *SA Power Networks considers that the AER's preliminary decision has not provided a sufficient allowance for SA Power Networks to maintain and operate new assets installed to meet the efficient augmentation of the network in accordance with its regulatory obligations and requirements during the 2015-20 RCP.*

SA Power Network's proposal will be considered in more detail in Section 6.4.2 below. However, at this point it is worth noting that the evidence for SA Power Networks' claim of "spatial related increase in capacity" leading to higher opex is not at all clear.

SA Power Networks' Revised Reset RIN provides little evidence of growth in capacity in any segment of its network and very limited growth in line length (see Figure 5.4 above). The majority of SA Power Networks' proposed capex is replacement capex, safety capex and non-system capex and it is not clear why any small residual capacity growth should lead to net increases in maintenance and operation of the network particularly as the high allowance for replacement capex should lead to a reduction in opex.

Recommendation:

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[129] Ibid, p 197.

[130] Ibid, p 201.

[131] Ibid.

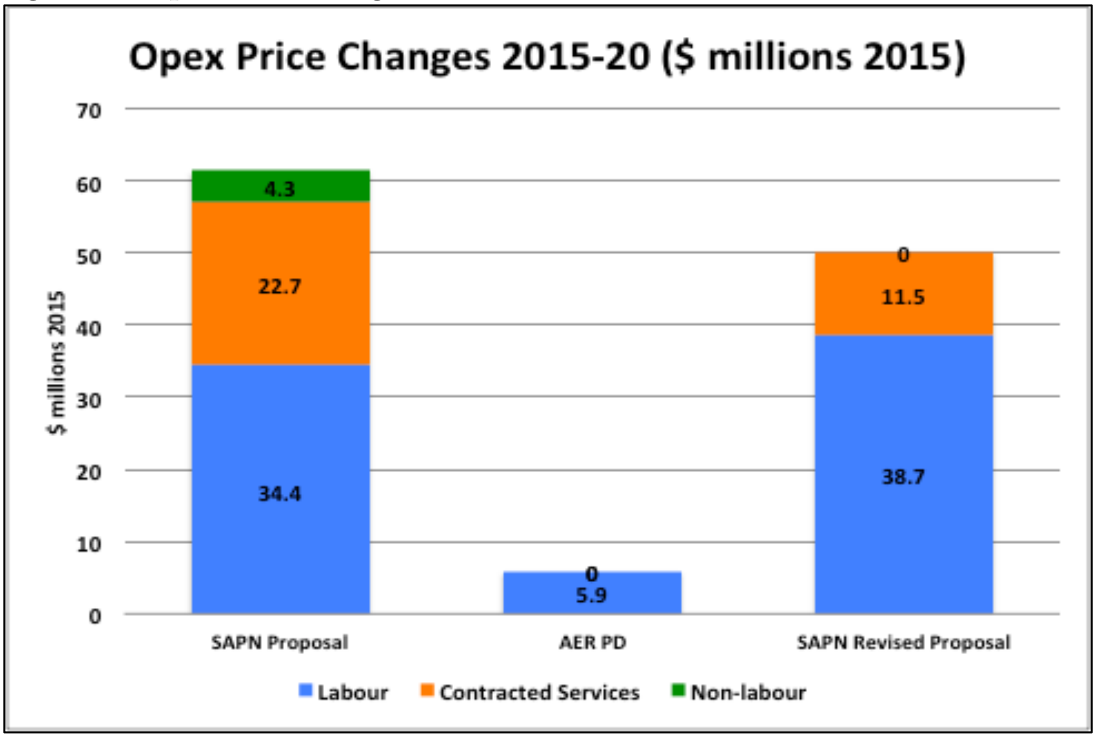
The AER not accept SA Power Networks' proposed increased opex as a result of increase in capacity (specifically the use of growth in transformer and substation capacity rather than ratcheted maximum demand).

6.4.1.2. Real Price growth

Real price growth includes increases in the real dollar costs for labour, contracted services and materials ("Non-labour"). Labour costs account for the majority of the operating expenditures and are the single largest factor in SA Power Networks' proposed increases in real price growth.

Figure 6.5 below illustrates SA Power Networks' original proposal, the AER's PD and SA Power Networks' revised proposal. SA Power Networks' revised proposal accepted the AER's position of no real price increases for non-labour materials inputs although, as discussed below, the AER includes contracted labour costs as part of the "non-labour" inputs and SA Power Networks does not accept the AER's position on contract labour costs.

Figure 6.5: Opex Price Changes 2015-20 ($ millions 2015)



Source: SA Power Networks, *Revised Regulatory Proposal, 2015-20*, Table 8.12, p 202; CCP2 analysis.

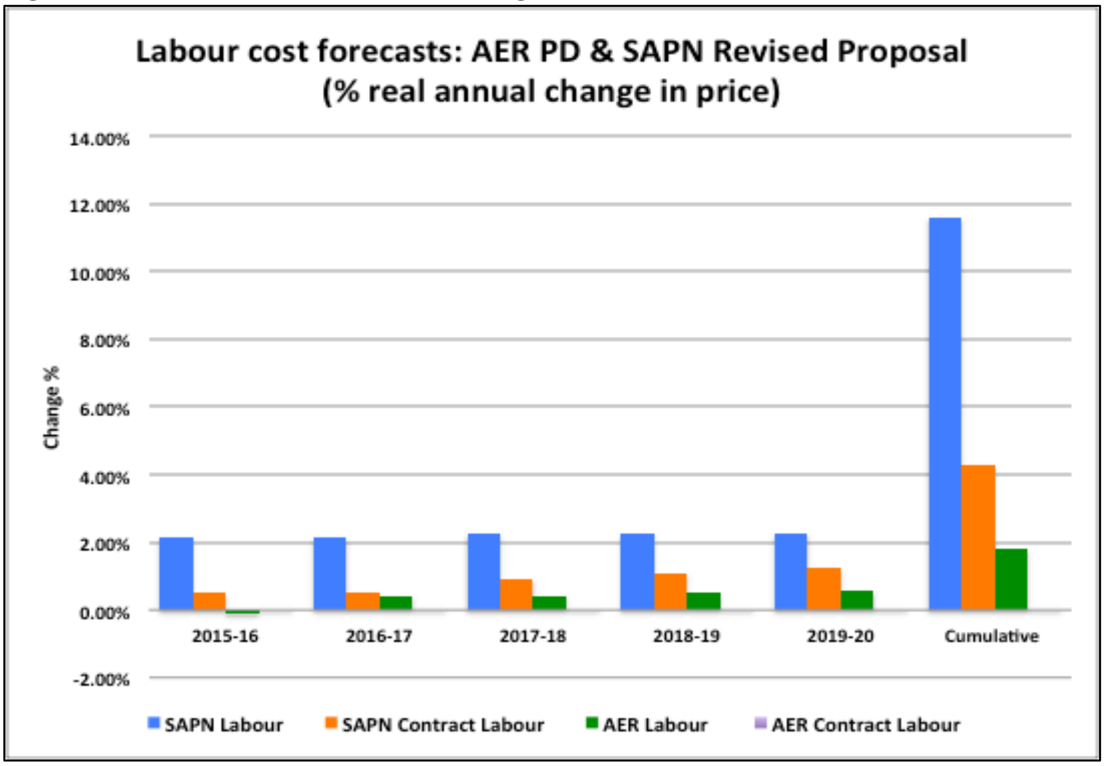
Therefore, the differences between the AER's PD and SA Power Networks proposals concern the forecasts of labour costs and contractor costs. Figure 6.6 illustrates the differences in annual price movements between the AER's PD and SA Power Networks' revised proposal.

Figure 6.6 also demonstrates that the cumulative impact of the different approaches is quite substantial. It is therefore important to consider in more depth the reasons for these differences.

The key elements of both proposals include the following differences:

- **labour costs**: SA Power Networks proposes to use its own Enterprise Agreement (EA) outcomes for the first two years of the 2015-20 RCP and use extrapolated costs for the remainder of the RCP. The extrapolated costs are based on benchmarked EA outcomes for "similar businesses", that is, all privately owned transmission and distribution service providers in Australia; and
- **contractor labour costs**: SA Power Networks proposes to apply an average of Deloitte Access Economics (DAE) and BIS Shrapnel's forecasts using the electricity, gas, water and waste services (EGWWS) wages price index (WPI).

Figure 6.6: Annual & Cumulative change in labour costs 2015-2020 (real $)



Source: SA Power Networks, *Revised Regulatory Proposal 2015-20,* Tables 8.14, 8.16 & 8.20; CCP2 analysis. Note: The AER does not specifically identify contract labour, but includes it in general CPI increases for "non-labour" costs. That is, "AER Contract Labour" has 0 per cent real price change and therefore the AER contract labour costs are not identified in the chart.

The AER's forecast of price changes differed in a number of other important ways to the forecast by SA Power Networks. For instance:

- The AER included contracted labour costs as part of the "non-labour" category of inputs. The non-labour inputs were based on five producer price indexes (PPIs).[132]
- The AER and SA Power Networks differed in the weighting that they gave to different components of the price growth allowance. The AER gave a weighting of 62 per cent for labour and 38 per cent for non-labour (including contracted labour).[133] In its revised proposal SA Power Networks gave a weighting of 46 per cent for labour, 44 per cent for contracted labour and 10 per cent for other cost items (materials). [134]
- The AER relies on DAE's forecasts of labour cost (excluding contract labour) increases based on the EGWWS index only as it considers these forecasts better take into account "current market conditions".[135] SA Power Networks uses EA projections for labour costs (as above) and average of DAE and BIS Shrapnel forecasts of EGWWS WPI for contract labour costs. SA Power Networks argues that this approach takes better account of private electricity industry labour costs.
- The AER states that its reliance on EGWWS index includes an implicit allowance for labour productivity growth and is therefore consistent with its benchmarking analysis. SA Power Networks' EA approach (for labour) does not include labour productivity growth in its labour costs. The AER states that: [136]

> *We consider zero productivity in conjunction with SA Power Networks' labour forecast is not likely to lead to an estimate consistent with the opex criteria".*

As stated above, the AER did not separately forecast contractor labour costs and included these latter costs in "non-labour" category along with materials costs as "contracted services". Therefore, the AER forecast no real increases in contracted labour costs.

6.4.2 Response to AER's PD and SA Power Networks' revised proposal for the rate of change

6.4.2.1. Output growth

The core remaining issue with respect to output growth is the measurement of the growth in maximum demand. The AER is using ratcheted maximum demand as applied in EI's economic benchmarking analysis, after analysis of a number of predictor variables. SA Power Networks proposes to use transformer and substation capacity

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[132] See AER, *Preliminary decision SA Power Networks distribution determination 2015-20*, Attachment 7, p 7-58. The five PPIs cover business, computing, secretarial, legal and accounting and public relations services.

[133] Ibid, p 7-58.

[134] SA Power Networks, *Revised Regulatory Proposal, 2015-20*, Table 8.19, p 222. This is different to SA Power Networks' original weightings of 44%, 54% and 2% respectively.

[135] See AER, *Preliminary decision SA Power Networks distribution determination 2015-20*, Attachment 7, p 7-55.

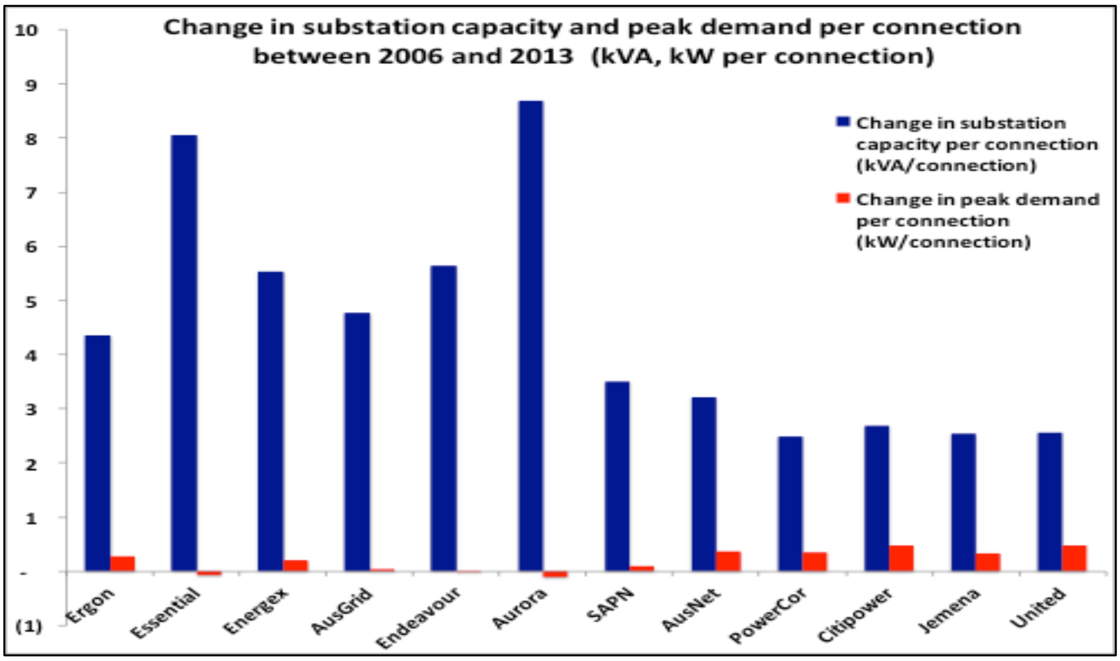
[136] Ibid, p 7-54.

growth. As noted above, SA Power Networks considers capacity growth (as measured by growth in transformer and substation capacity) is a better predictor of opex requirements as it taps into SA Power Networks' "spatial demand growth".[137]

However, as EI pointed in its initial analysis, growth in capacity does not necessarily correspond to growth in outputs (maximum demand for electricity). For instance, there is evidence that across the NEM, DNSPs have greatly expanded capacity while demand growth was flat or declining between 2006 and 2013. The evidence suggests that this has resulted in growing spare capacity on the DNSPs' networks, including SA Power Networks' system.

Figure 6.7 summarises the significant difference between the growth in substation capacity and the growth in demand between 2006- and 2013.

Figure 6.7: Change in substation capacity and peak demand per connection between 2006-2013



Source: Mountain B., Advice to the AER on its Preliminary Determination for 2015-20, July 2015, Figure 1, p 5.

Figure 6.7 illustrates the problem of using forecast changes in substation and transformer capacity in place of the AER's forecast of ratcheted maximum demand. SA Power Networks' approach raises the following issues:

- It is inconsistent to use a demand-based measure (ratcheted maximum demand) in the historical analysis but then use a capacity-based measure (substation and transformer capacity) in the forecasts of output growth.

[137] SA Power Networks, *Revised Regulatory Proposal, 2015-20*, p 201.

- SA Power Networks has not provided any statistical analysis to suggest that capacity build is a better measure of efficient investment than ratcheted maximum demand (whether historical or forecast). Such an analysis would be required in order to justify a departure from the EI benchmarking outputs.
- EI conducted an investigation into the use of capacity measures versus demand measures in its benchmarking study. EI recognised that when assessing efficient expenditure (whether historical or forecast), it should be based on the capacity **actually used by the consumers** (i.e. actual maximum demand). EI concluded that ratcheted maximum demand is the most appropriate measure as it meant that networks are given credit for the costs of building capacity to meet maximum demand at a point in time, even if maximum demand was lower in subsequent years.[138]
- SA Power Networks' approach would provide an ongoing incentive/reward in the opex allowances as well as their capex allowance for building inefficient transformer capacity (i.e. in excess of forecast demand) as a proportion of their overall investment allowance (noting that the AER approves the total amount, not individual projects).
- EI's approach already provides opex compensation for spatial demand growth of the type forecast by SA Power Networks ("pockets of growth"). That is, in adopting the EI approach, the AER allows for growth in customer numbers and in circuit line length, both of which will capture much of the costs associated with servicing new pockets of growth.
- If SA Power Networks' claims about the additional opex costs associated with managing growth in substation/transformer capacity are correct (and it is not clear if this is the case), then consumers must already be carrying the burden of excess capacity investment in historical opex costs (as well as capital costs). In addition, these additional opex burdens are likely to be incorporated into the base year 2013-14 and will therefore be carried forward into the 2015-20 regulatory period. This would suggest that the 2013-14 base year is not efficient.

Overall, therefore, it is recommended that the AER does not accept SA Power Networks' revised proposal for output growth of $34 million ($2015). The AER's forecast of output growth of $21 million recognises customer number growth and provides sufficient growth related opex to meet the low and quite localised growth in customer numbers and energy use.

Recommendation

The AER not accept SA Power Networks' proposed increased opex as a result of the increase in capacity (specifically the use of growth in transformer and substation capacity) rather than ratcheted maximum demand).

[138] See for instance, Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November 2014, pp 10-11.

6.4.2.2. Real Price Growth

SA Power Networks' original proposal included a total of $61 million ($2015) for real price changes over 2015-20 including $57 million relating to labour and contractor costs and $4.3 million for increases in the prices of materials.

SA Power Network's revised proposal includes $50 million ($2015) for real price growth in opex, a figure that is still substantially greater than the AER's allowance of $26 million (see Figure 6.5 above).

It would seem that the most appropriate forecast of price increases in materials is the AER's forecast of CPI, although it should be noted that relative to the expectations when the last regulatory allowance was set, actual material costs have undergone significant declines. Thus, a CPI allowance for material costs is quite generous to SA Power Networks. However, in the absence of any consistent and objective forecast of future material price trends CPI is a more reasonable assumption and one that is accepted by SA Power Networks in its revised proposal.

The core issues in terms of real price growth relate to the different forecasts of labour and of contract labour costs. As Figure 6.6 above demonstrates, there are very significant differences between the AER and SA Power Network in the forecasts, reflecting different forecast approaches and different weightings of the various cost components.

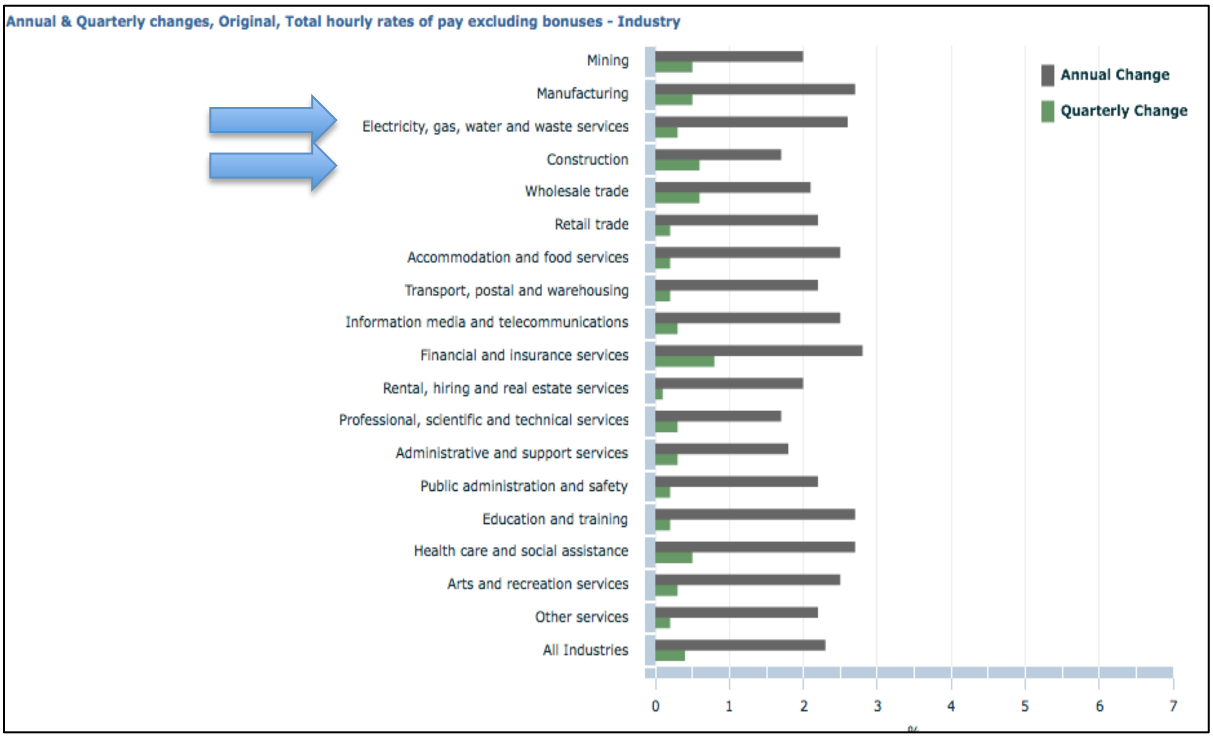
The following comments are made in response to both the AER's PD and SA Power Networks' revised proposal. These comments are in addition to the arguments already put by CCP2 in response to SA Power Networks' original proposal. They include:

- There are many submissions to the AER, including submissions from business organisations, that suggest SA Power Networks' labour cost forecasts are too high and do not represent a realistic or reasonable expectation of the cost of labour over the five year period. In general, sustained real labour price increases in the order of 2.15 to 2.26 per cent above CPI are not credible given current trends in wages generally. Figure 6.8 below, for instance, illustrates the changes over the past year in the wage price index by industry sector.

- The ABS June Quarter data also indicates that:
  - EGWWS WPI grew at 2.6 per cent for the year, but just 0.3 per cent in the June Quarter 2015;
  - Construction industry WPI grew at 1.7 per cent for the year and 0.6 per cent for the June Quarter;
  - Administrative and support services grew at 1.8 per cent for the year and 0.3 per cent for the June Quarter.

  This data, which covers both specialist and non-specialist labour, provides no support for the SA Power Networks claim of increases above CPI of more than 2 per cent per annum on average for each of the next five years.

Figure 6.8 : ABS Wage Price Indexes June Quarter 2015 and Annual 2014-15



Source: Australian Bureau of Statistics, "Report No 6345.0 – Wage Price Index Australia, June 2015", Release date 12 August 2015. The quarterly WPI rise for SA across all sectors was 0.2%.

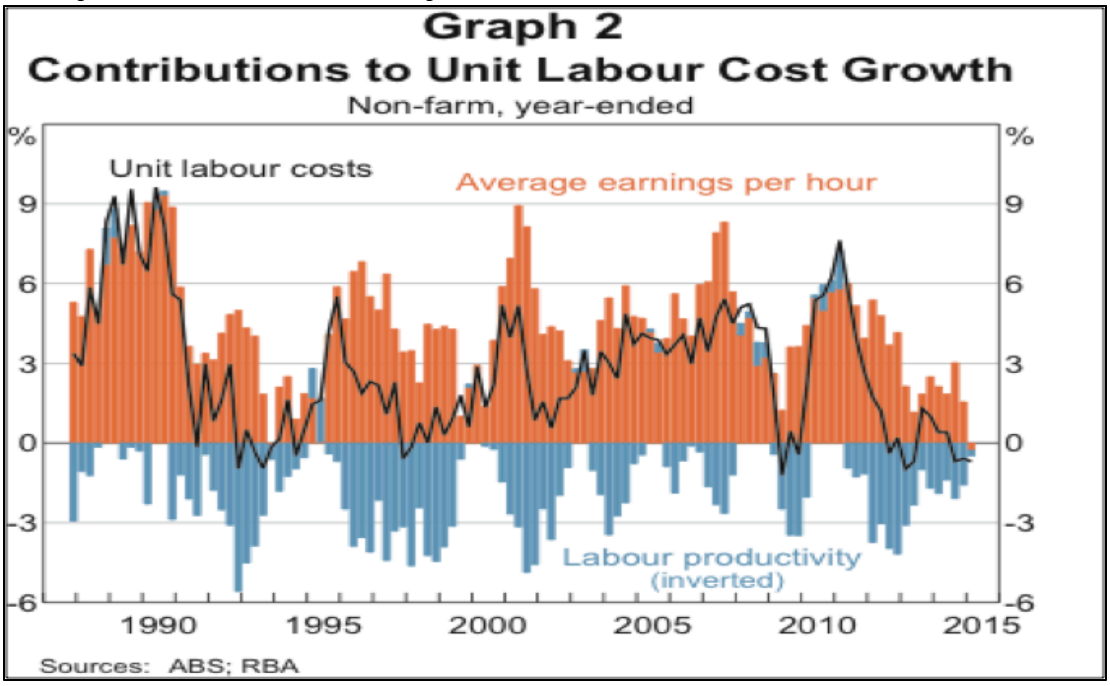
- Similarly, the Reserve Bank of Australia (RBA) recently published a research report: "Why is Wage Growth So Low". The report concluded as follows:[139]

> *Wage growth has declined markedly in Australia over the past few years. At the same time, stronger growth in labour productivity has worked to contain growth in labour costs. … The size of the decline in wage growth has been larger than simple historical relationships would suggest, which might be explained by various characteristics of the current episode.*

Figure 6.9 illustrates the two trends cited in the RBA report, namely, declining growth in wages and increasing labour productivity. It is difficult (and would be concerning) to argue that the SA electricity industry should somehow be immune from these two trends.

[139] Jacobs D., and Rush Alexander, "Why is Wage Growth So Low", RBA Bulletin, June Quarter 2015, p 9.

Figure 6.9: Unit labour cost growth in Australia to 2015



Source: RBA Bulletin, June Quarter, 2015, p 9.

- The obligation on the AER is to only allow operating costs that reasonably reflect the prudent and efficient costs of delivering network services, meeting regulatory obligations maintain safety and a realistic expectation of demand and cost inputs.

  It would be inconsistent with these requirements, and undermine the incentive nature of the regulatory framework, for the AER to automatically allow a pass through of a network's EA arrangements.

- One reason for the high real price increases proposed by SA Power Networks is its forecast CPI. In its revised proposal SA Power Networks is forecasting a CPI of 2.06 per cent, a figure that is significantly below the AER's current forecast of 2.55 per cent.

  As SA Power Networks' EA is expressed in nominal dollars (4.25 per cent nominal annual increase) the real price increase is higher than it would be under the AER's inflation forecast. In other words, the inflation forecast is feeding into the rate of growth (or at least would be if the AER accepted SA Power Networks' approach), and this then raises issues about how the real increase in wages should be assessed.[140]

- SA Power Networks states that its use of EA outcomes "to inform labour cost escalation" rates is "also consistent with"[141] the 2010 Australian Competition

[140] The forecast opex models require inputs that are in real dollar terms.

[141] SA Power Networks, Revised Regulatory Proposal, July 2015, p 206.

Tribunal (Tribunal) decision on the AER's approach to Ergon's labour cost escalators.[142]

A review of the Tribunal's 2010 decision indicates that the Tribunal did give some credence to Ergon's Union Collective Agreement (UCA) for the period up to its expiry in 2010-11. The Tribunal noted, in particular, the circumstances in which the UCA was negotiated to assess whether it was a 'fair' deal.

However, the Tribunal did not agree that the UCA was relevant to the forecast beyond its termination date in 2010-11. The Tribunal confirmed that beyond 2010-11 the AER was able to determine the best approach to the forecast task in line with the opex objectives, using information from Ergon but also from other independent sources.

Therefore, it is an open question for the AER to resolve with respect to SA Power Networks EA for 2015-16 and 2016-17, given the Tribunal's 2010 decision.

Nevertheless, we regard the AER's wider industry based approach for 2017-18 to 2019-20 (using the EGWW WPI) is significantly more preferable than SA Power Networks' more narrow approach which is based on a scan of EAs for private electricity networks. As stated above, SA Power Networks' forecast for 2017-18 to 2019-20 is based on examination of EA's for similar privately owned industries (effectively, other privately owned distribution and transmission electricity companies)

SA Power Networks' consultant, Frontier, explains this narrow selection of comparator organisations by suggesting that public sector employees are subject to more pressure to restrain price increases than the private sector employees. Therefore, including public sector EAs in the analysis would distort the forecast downwards.[143] However, this does not appear to be a credible argument for forecasting labour cost increases beyond 2016-17.

The recent RBA assessment of the WPI for example, set out in Figure 6.10, provides no evidence that such a restriction on the "sample" of EA's is required. Both the private and public sectors have seen very similar declines in the WPI.

Even for the period covered by SA Power Networks EA (2015-16 and 2016-17), it is not sufficient to consider the EA outcomes in isolation. It is the total labour cost that is of interest and we would have expected that SA Power Networks, as a prudent operator, would have negotiated certain productivity improvements in conjunction with any increase above CPI in unit labour costs.

Therefore, while we believe the AER should carefully review the Tribunal's decision, this does not mean that the AER's forecast of labour costs for 2015-16 to 2017-18 is wrong, once a benchmark labour productivity factor is taken into account, for instance

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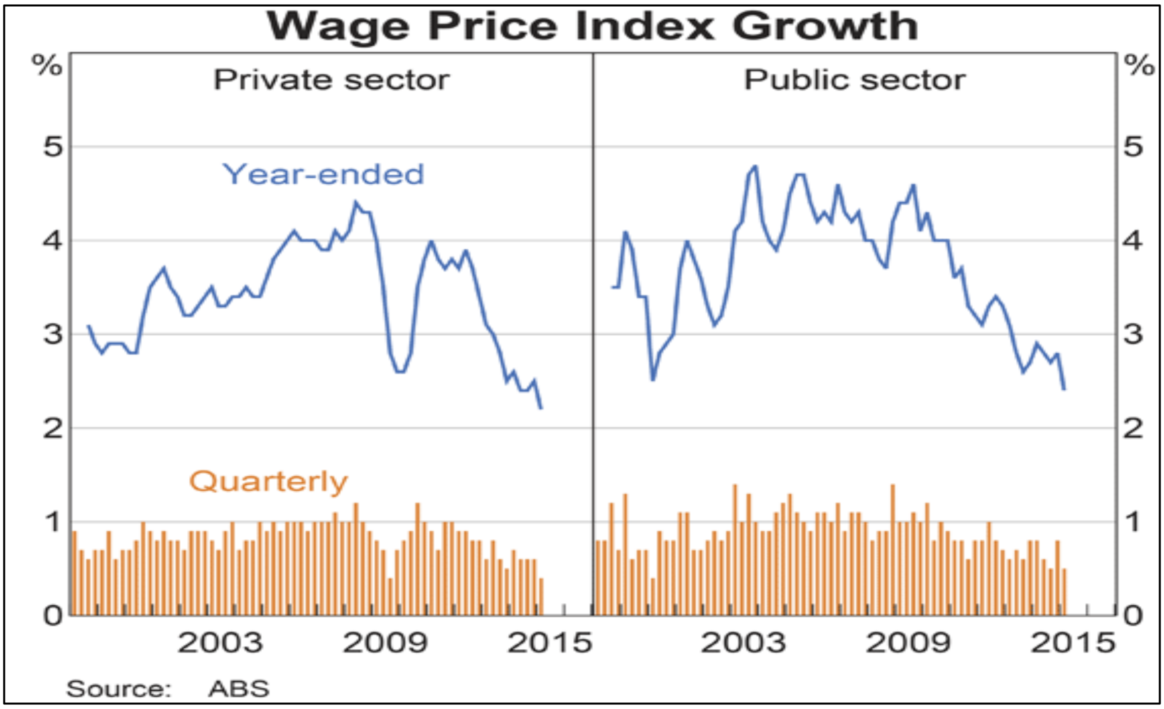
[142] *Application by Ergon Energy Corporation Limited (Labour Cost Escalators)*(No 3) [2010] ACompT 11, 24 December 2010.

[143] SA Power Networks, *Revised Regulatory Proposal 2015-20*, July 2015, p 207.

using the wage and productivity data from the RBA or ABS that is illustrated in in Figure 6.9 above.

Figure 6.10: RBA Wage Price Index Growth for the Private and Public Sectors



Source: RBA, "Factors of Production and Labour Market", 5 August 2015.
http://www.rba.gov.au/chart-pack/factors-prod-labour-mkt.htm

Moreover, SP Power Networks has not included productivity savings in its forecasts of labour costs beyond the current EA. This is of concern as it does not represent prudent practice and is not consistent with the general trend in labour costs.

In summary, while it is acknowledged that SA Power Networks' current EA includes a nominal wage increase of 4.25 per cent per annum, it is not accepted that this increase, translates automatically into an equivalent real price increase in the context of the rate of change component of the opex allowance for the period 2015-17. In addition, SA Power Networks' forecast for the last three years of the RCP has little basis and should not be accepted.

Recommendations:

The AER review the approach it has adopted for 2015-16 and 2016-17 labour costs, taking into account decisions by the Tribunal. However, also consider the impact of SA Power Networks alternative inflation forecast that changes the real price increase in labour costs and reasonable expectations for labour productivity growth to reduce unit labour costs.

The AER retain its approach, using Deloittes Access Economics (DAE) forecasts of EGWWS wages price index for 2017-18 to 2019-20

With respect to contracted labour, the competitive tension in the tendering process should ensure that contracted labour costs (including average wage increases and productivity) would not increase above the EGWWS WPI.

More specifically, the AER's assumption that these costs should not be subject to any real price increases over the course of the 2015-20 RCP is reasonable. However, it would be useful if the AER separately identified these contractor costs rather than including them in "other non-labour costs"

Recommendation

The AER continue to assess contract labour costs as CPI, but it would be preferable to have these costs separately identified given the extent of contracting services now used by the DNSPs.

Some final queries and comments on price changes.

The AER should undertake further investigation of its proposed split between labour and contract labour categories. SA Power Networks has suggested that the AER's split of 65 per cent labour, 35 per cent non-labour (contractor costs) is based on older studies and there has been considerable change in how businesses are structured since that time. Without knowing the specifics of SA Power Networks claim of increasing proportions of contractors in its overall labour force, there is a general increasing trend to using contracted labour for many of the traditional tasks.

Recommendation

The AER review its assumptions regarding the split between labour and non-labour categories, taking into account the more recent information from SA Power Networks and other DNSPs.

6.4.2.3. Productivity changes

The AER explains that the forecast productivity component of the base-step-trend approach: "is our best estimate of the **shift in the frontier of the efficient service provider**".[144] [emphasis added]. In that sense, it is an industry wide parameter rather than specific to SA Power Networks. The AER argues that the in a competitive market, there would be a constant shift of the best performing companies in an industry to greater productivity and that would, in turn, drive all other industry participants to improve their performance.

The productivity change factor is meant to provide that same incentive on the DNSPs.

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[144] AER, *SA Power Networks Preliminary Decision 2015-20*, Attachment 7, p 7-65.

CCP2 supports the principle behind the adoption of this productivity factor, particularly as the evidence supports a view that the Australian network industry generally is less efficient than its international peers. Standing still should not be an option particularly when there is an initial need to "catch up" with the best.

Both the AER and SA Power Networks, however, have forecast no change in productivity over the RCP. The AER does suggest that some aspects of productivity changes are captured in the labour cost measures and in the output growth measures. For example, the EGWWS WPI based forecast includes an assumption of productivity growth that offsets some increases in unit labour costs. The AER states: [145]

> *We consider labour productivity and economies of scale to be sources of productivity and are linked to the labour and output measures.*

The AER then explains its zero productivity forecast for SA Power Networks as being a reflection of:[146]

- The interaction between productivity, price growth and output growth (as above);
- The negative productivity for DNSPs on the efficient frontier is not representative of the underlying productivity trend and the increase in service inputs relative to outputs is not likely to continue for the forecast period; and
- Measured productivity for electricity transmission and gas distribution industries are positive for the 2006-13 period and forecast to be positive.

While SA Power Networks has accepted the application of a zero productivity growth it states that the AER has no reason to believe the negative productivity growth will turn around in the 2015-20 RCP. In addition it considers that the AER's decisions on many of SA Power Networks expenditure proposals implicitly assumes a growth in productivity when there is no evidence to support such an assumption.

SA Power Networks views (summarised above) suggest an industry that has not faced up to the reality of operating in a market where customers have increasing choice about when and how they use electricity. It is a very unsatisfactory staring point to claim that negative productivity in the past means that the default assumption is negative productivity in the future.

The AER has also adopted an unnecessarily conservative approach to the productivity factor by assuming zero productivity growth. That is, the AER's decision lacks any substantial incentives to improve productivity and recover from the decline observed over 2006-2013. As such, the decision fails the "competitive market" test outlined in Section 3 of this advice.

[145] Ibid, p 7-64.
[146] Ibid, p 7-65.

The following matters are relevant to the three factors that the AER considered were relevant to its conclusions that the productivity factor should be set to zero.

- There is an interaction between productivity, price growth and output growth given the measures of price and output as the AER claims. However, productivity growth can occur due to other factors such as general technology changes, capital investment and improved management skills. For instance, the AER has not investigated the opportunity for opex productivity growth arising from technology change. Nor has it transparently considered how the capex investments of 2010-2015 and in the 2015-20 RCP should drive higher productivity. <u>Consumers are constantly funding these developments but there is little reduction in costs to show for all this capex.</u>
- The AER justifies its decision by reference to the fact that it did not incorporate a negative productivity growth factor even though this would be consistent with the trend since 2006. This is not an explanation for the AER's decision not to introduce a positive productivity factor. Rather it demonstrates one of the limitations of the EI benchmarking when applied to forecast conditions; and
- The fact that electricity transmission and gas distribution industries can show positive productivity growth even though they also face the challenges of high capital investment in the past and prospective declines in output in the future, should be a reason enough to expect electricity DNSPs to also improve their productivity over the forecast period.

CCP2 would add that almost all other industries have turned productivity around in recent periods (see Figure 6.9 above) and it seems unreasonable for consumers to fund the DNSPs inaction on this matter. More specifically, the AER's approach effectively allows DNSPs to "retain" their base year opex and decrease their productivity (compared to average of 2006-20013 as measured by EI) into the 2015-20 RCP.

The EI data strongly suggest that there should be a productivity figure that <u>at least</u> moves the efficiency of SA Power Networks (and others) over 2015-20 RCP back to an efficient frontier point that is closer to the average MFTP for 2006-13.

Without a proactive approach from the AER, the base-step-trend approach will inevitably lead to stagnation of productivity growth, particularly as the 2013-14 base year reflected lower productivity compared to the EI's average score, and it appears that the EBSS has not delivered reductions in opex forecasts, although this is the intended outcome of the EBSS.

Recommendation:

The AER reconsider its forecast of zero per cent growth in the opex productivity factor, particularly given productivity growth in related industries (electricity transmission and gas distribution) and productivity gains in the wider economy.

6.4.3 Summary of Opex Output Growth Measures

Table 6.2: Summary of Opex Output growth Measures

	Parameter	**AER Preliminary Determination**	**SAPN's revised proposal**	**Response**
Output growth	Customer Numbers	Accept SAPN's initial forecast	Agree	Agree
	Circuit line length	Accept SAPN's initial forecast	Agree	No comment
	Maximum demand	Use SAPN's forecast of ratcheted maximum demand	Use growth in substation and transformer capacity	Agree with AER. Capacity growth is not appropriate
Price Change	Labour	Reject SAPN's forecast of labour costs,	SAPN disagrees, applies its initial proposal to labour and contract labour costs	Qualified acceptance of AER's approach
	Non-labour	CPI (includes contract labour)	CPI for materials Disputes weightings used by AER	Agree with AER re contract labour & materials Requests AER to investigate weightings issue.
Productivity Change	Productivity	Zero	Zero	Do not accept the AER's PD

6.5 Step Changes in Opex

6.5.1 Overview

The AER's Expenditure Forecast Assessment Guideline makes clear that step changes in the opex forecasts are those increases in costs that are not already compensated through other elements of the opex forecasts. These other elements of the opex forecast include the base year efficient opex and the 'rate of change' component.

For example, the AER states that: "a step change should **not double count the costs of increased volume or scale compensated through the forecast change in output**".[147] Other questions that need to be considered in the assessment of whether an opex proposal warrants a step changes include:[148]

- Is there a change in circumstances driven by exogenous factors that the NSP cannot control?
- Were other options considered and is the selected project the most efficient way of achieving the required outcomes?
- Are all relevant costs and benefits of the selected project accounted for?
- When will the event/program be required and over what period should costs be recovered?
- Can costs of program be recovered within the overall opex allowance, e.g. from reductions in other costs?

The step changes should also be 'non-trivial'. This is because for small increases in expenditure in one area of the business there are likely to be offsetting number of small decreases in other expenditure areas and these decreases may not necessarily have been nominated by the networks.

Step changes should, therefore, be reserved for significant new cost increases (positive step change) or significant cost reductions (negative step change). It is interesting to note that we rarely see a negative step change in opex proposals even following substantial increases in capex investments, which could be expected to reduce opex in future years.

6.5.2 Summary of AER's PD and SA Power Networks' revised proposal

Some 14 per cent of SA Power Networks' original opex proposal consisted of positive step change events. In total, SA Power Networks sought an increase in opex of some $217 million ($2015).

SA Power Networks stated that the step changes reflected enhanced compliance with existing regulations, regulatory changes, new customer technologies, ongoing changes in customers' expectations and increased costs of inputs. The major component of the $217 million related to a number of step changes in SA Power Networks' legal and regulatory obligations.

The AER has rejected almost all of SA Power Networks' proposed step changes, allowing only $4 million as a step change relating to the implementation of the National Energy Consumer Framework (NECF) and an efficient capex/opex trade-off. The AER also accepted the negative step change following the reduction in SA Power Networks' distribution licence fee (effective from July 2015).

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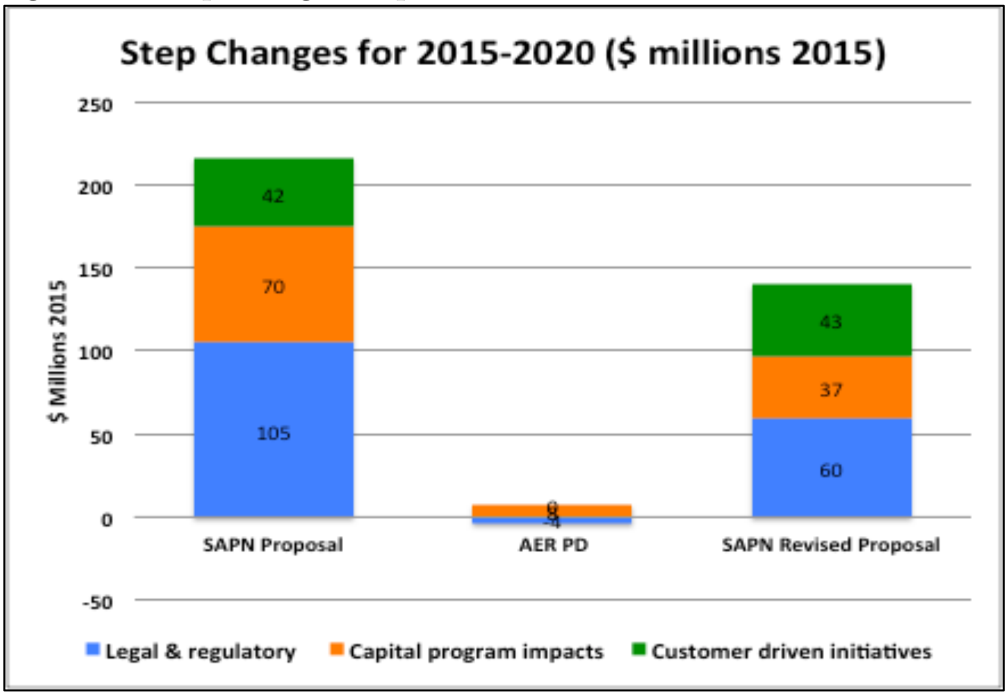
[147] AER, *SA Power Networks Preliminary Decision 2015-20*, Attachment 7, p 7-71.

[148] See ibid, p 7-72

Figure 6.11 summarises SA Power Networks' initial and revised proposal and the AER's PD.

Figure 6.11: Step Changes Proposed for 2015-20 ($ millions 2015)



Source: SA Power Networks, *Revised Regulatory Proposal 2015-20*, Table 8.22; AER, *Preliminary Determination 2015-20*, CCP2 analysis.

In making its assessment of SA Power Networks' original step change proposal, the AER also set out some important principles that are relevant to SA Power Network's revised proposal.

- An assumption that base year opex (after adjustment) reflects the costs of meeting existing regulatory obligations and maintaining the reliability, safety and quality of supply of standard control services; [149]
- A focus on the impact of a program on the total opex allowances: For instance, while some new costs will be incurred, other costs will decline; it is the net cost impact that is important.[150]
- Similarly, new or expanded opex programs can be financed out of savings in other areas; the AER's decision does not prevent that or penalise a DNSP under the EBSS.[151] The AER states:[152]

> *SA Power Networks has not demonstrated this to us* [consideration of internal trade-offs]. *In many cases it has just identified a need at the program or project*

[149] ibid, 7-73.
[150] ibid, p 7-74.
[151] Ibid, p 7-74.
[152] Ibid.

level and then ***added it to the total opex it incurred in 2013-14****.* [emphasis added]

- Expenditure related to efficiency improvements will generally not be considered as step changes because there should be offsetting benefits, including potential payments under the incentive schemes (EBSS, CESS and STPIS).[153]
- There was little evidence of changes in SA Power Networks' regulatory or legal obligations since the base year 2013-14,[154] despite SA Power Networks making references to a variety of regulations and laws. Nor was there evidence of changes in expectations from the relevant regulatory authorities such as ESCoSA and OTR.
- SA Power Networks' original proposal lacked compelling evidence in support of its customer driven initiatives or changes in community expectations that should drive increased opex.[155]

In its revised proposal, SA Power Network argues that the AER's allowance fails to recognise the impact of the new expenditure drivers, most particularly the expected impact of legal and regulatory changes during 2015-20.

SA Power Networks believes that the AER is acting unreasonably when it expects these additional costs to be recovered through efficiency improvements when SA Power Networks is already operating at the efficiency frontier. SA Power Networks also believes the AER must recognise the expenditures required to reasonably meet customer expectations as identified in its customer engagement research.

SA Power Networks has, therefore, submitted a revised regulatory proposal that includes a total step change of $140 million ($2015). This is some 35 per cent below its initial proposal but well in excess of the AER's PD allowance of $4 million. It includes 11 categories of step changes with multiple sub-categories, itself an issue for any evaluation of the proposal.

While overall, SA Power Networks' revised proposal represents a significant reduction from its initial proposal, SA Power Networks' has continued to propose the same level of expenditure in the "customer driven initiatives" step changes.

A brief summary of SA Power Networks' revised proposal by category of opex follows as it illustrates the problem highlighted by the AER in the quotation above. That is, the issue of SA Power Networks applying for a step change based on cost increases arising from relatively small projects. There could be many other small changes that lead to cost decreases but these are not examined in SA Power Networks' proposals.

For convenience, Figure 6.12 below is a repeat of Figure 6.3 above. It is repeated here as it indicates the trends in expenditures from 2006 to 2013. The step change proposal should be considered against the background of these expenditure trends. For instance,

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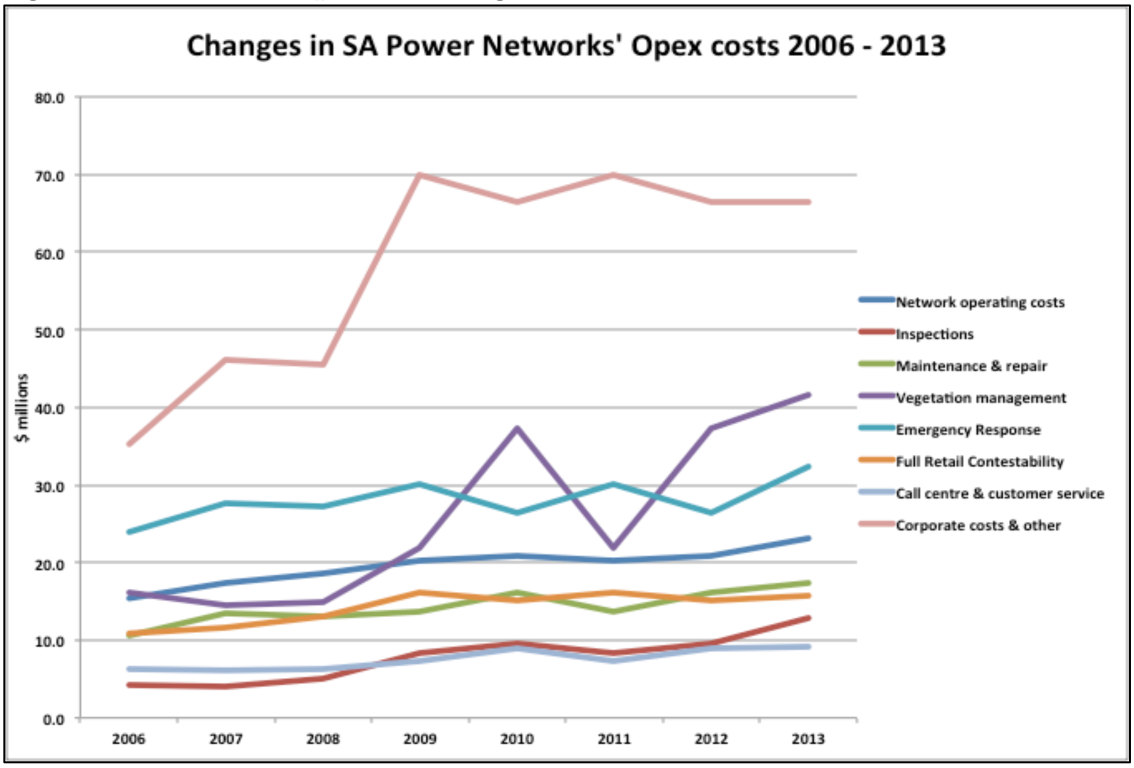
[153] Ibid.
[154] Ibid, p 7-75.
[155] Ibid, p 7-76.

if there is high growth in a segment of opex during 2010-15, it is important to consider whether another positive step change is appropriate.

Section 6.5.2.1 – 6.5.2.3 below summarise the AER's PD and SA Power Networks' revised proposal.

The response to these issues is set out in 6.5.3.1 to 6.5.3.3.

Figure 6.12: Historical opex cost changes 2006-13($ nominal)



Source: SA Power Networks, Economic Benchmarking Consolidated 2006-2013, "3.Opex". CCP2 analysis. Note: The "Corporate costs & other" category includes GSL and DM expenditures.

6.5.2.1. Legal and Regulatory Step changes (SA Power Networks' Revised Proposal)

Following the AER's PD, SA Power Networks' revised proposal has reduced the total step change in this category from $105 million ($2015) to $60 million. However, this is still well above the AER's PD allowance for step change of -$4 million. The major subcategories of proposed step changes are as follows, noting that the AER has rejected almost all but the most minor elements (pass through of NECF related costs):

- **Asset inspections**: SA Power Networks seeks nearly $35 million ($2015) for additional asset inspections covering two categories, namely 'no access' poles and asset inspections in high bushfire risk areas. SA Power Networks claims it was not compliant in the base year and it needs to increase its inspection rate to comply with its SRMPTMP and good industry practice.
- **Workplace health and safety**: SA Power Networks proposes an additional $9 million on the basis of changing regulation and it non-compliance in the base year.

- **Energy laws & regulations**: SA Power Networks claims it will incur step changes in costs of between $21 million and $31 million, due to the RIN requirements, the introduction in SA of the National Energy Consumer Framework (NECF), implementation of the AEMC's changes to the distribution network pricing arrangements in the NER and to the expected rule changes to introduce competition in metering, and increased PV penetration in SA.
- **Distribution licence fee**: There is a negative step change of $5 million as a result of the SA Government reducing the distribution licence fee.

6.5.2.2. Capital Program Impacts (SA Power Networks' Revised Proposal for capex and opex)

The AER significantly reduced SA Power Network's original proposal from $70 million to $8 million ($2015). SA Power Networks' revised proposal is $37 million of which around half is in support of its capex proposal for IT technology. The key step change components are:

- **Information technology**: The AER did not allow any step change for IT related opex step change. SA Power Networks' revised proposal is $19 million, which is less than half of its original proposal. SA Power Networks states that the opex is required to support the planned updating of key IT systems including data centre, enterprise information security foundation, SAP foundations, and CIS OV replacement.
- **Mobile radio migration**: SA Power Networks plans to migrate its mobile radio network capacity to the SA Government Radio Network. The AER accepted SA Power Networks' initial proposal of a step change of $7.8 million. On the basis of advice from the SA Government, SA Power Networks has proposed a step change cost of $12.8 million in its revised proposal.
- **Non-network solution (Bordertown):** SA Power Networks is seeking an additional $1.3 million step change to support its non-network solution in Bordertown (following a similar cost benefit analysis to the RIT-D) namely, a network support agreement with a third party generator, lasting to 2021.
- **Data quality:** SA Power Networks sought a step change of $3.9 million to implement a Customer Data Quality Plan that extends the work undertaken in the 2010-15 regulatory period. SA Power Networks cites its regulatory obligations to provide more, and more accurate data such as customer address data. The AER did not accept this expenditure as a step change, however, SA Power Networks has included it in its revised proposal.

6.5.2.3. Customer Driven Expenditure (SAPN Revised Proposal)

SA Power Networks' initial proposal included step changes for customer driven expenditure of some $42 million ($2015). This proposal was rejected in its entirety by the AER largely on the basis that SA Power Networks did not provide sufficient evidence of the need for additional expenditure over existing expenditure and that at least some expenditure was discretionary in nature.

In its revised proposal on customer driven expenditure, SA Power Networks did not accept any aspect of AER's PD and again proposed an opex of $43 million ($2015) in its revised proposal. A summary of the key components of the customer driven expenditure is set out below.

- **Vegetation management**: In its initial proposal SA Power Networks' proposed a step change of $32 million ($2015), which was rejected by the AER. SA Power Networks' revised proposal seeks a step change of $33 million ($2015). The opex is justified as a "reasonable" step change driven "by industry developments and learnings <u>and by the expectations and requirements of electricity consumers</u>" as revealed in SA Power Network's CE program. [SA Power Networks' emphasis][156]
- **Customer Service:** SA Power Networks' original proposal sought a step change of $4.3 million for additional customer services to comply with its SRMTMP, meet expressed needs of consumers and manage the changing operating environment.[157] The AER's PD has rejected this step change largely on the basis that these expenditures are discretionary and should be managed within its existing budget. SA Power Networks did not accept the AER's revision in its revised proposal.
- **Community Safety**: In its original regulatory proposals, SA Power Networks' sought a step change of $5.4 million for community safety, an amount which it states is required by compliance with its SRMTMP and by feedback from its customer engagement programs.[158] The AER's PD rejected this step change on the basis that some expenditure was discretionary and, more generally, SA Power Networks' did not provide justification for why a step change above existing expenditure was required. SA Power Networks did not accept the AER's revision in its revised proposal.

The following Sections 6.5.3 will provide a response to the proposed step changes. Although some step changes may be worthy of further consideration by the AER, the majority of the proposed step changes do not adequately meet the criteria set by the AER for a step change (see Section 6.5.1 above).

Moreover, as demonstrated in Figure 6.12 above, many of the opex cost items have increased over the 2006-13 period, suggesting that the base year 2013-14 has already incorporated much of the additional expenditures required by the business for various opex related compliance and customer service activities.

Recommendations:

The AER reject the overall number and quantum of the proposed step changes in SA Power Networks' revised regulatory changes. The majority of the proposed steps do not reflect additional requirements and are captured in the base year or output growth.

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[156] SA Power Networks, *Revised Regulatory Proposal*, 2015-20, p 275.

[157] Ibid, p 284.

[158] Ibid, p 287.

The step changes should also be considered in the light of the increases in most opex categories between 2006-13, which suggests that the base year 2013-14 would be higher than the average for the 2010-2015 RCP.

6.5.3 Response to AER's PD and SA Power Networks' revised proposal for the base year

6.5.3.1. The legal and regulatory step changes

- **Asset Inspections**:
  In rejecting SA Power Network's initial proposal for increased allowances for asset inspections for no access poles and underground cables, the AER stated that such activities were not a response to a change in regulation and it was up to SA Power Networks to prioritise its expenditures if it believes more inspections will result in future cost savings. This aligns with the AER's principles discussed in Section 3 above. In its revised proposal, SA Power Networks responded that it was not compliant with its regulatory requirements in the base year (2013-14) and therefore needs a step change in opex funding to achieve that standard.

  SA Power Networks reasoning based on its "non-compliance" in the base year 2013-14 is not satisfactory. As illustrated in Figure 6.12, by 2013 SA Power Networks' expenditure on asset inspections had more than doubled since 2006. SA Power Networks should by now have sufficient information on the status of its poles in various other areas so that it can (if deemed necessary) focus more of its inspection activity on "no access" poles and underground cables without additional funding.

  SA Power Networks also has an historically high allowance for replacement capex to progressively address issues identified in these inspections. To the extent that a coordinated program of inspections and replacement will reduce emergency expenditure, SA Power Networks will receive compensation for any additional expenditure through the incentive mechanisms (CESS/EBSS and/or STPIS) and lower GSL payments.

  The AER also rejected SA Power Networks' proposal to increase the rate of asset inspection in HBRAs. The AER stated that while it agrees it would be good practice to increase inspection rates, it is not convinced SA Power Networks requires additional funding and, in any case, does not agree with their approach to costing additional inspections.

  SA Power Networks' proposal to increase the asset inspection cycle in HBRAs from 10 years to 5 five-years is worthy of further consideration by the AER.

  That is, it seems a reasonable response to changes in industry practice and community expectations and is consistent with SA Power Networks' general obligations. Unlike the higher inspection rates for 'no access poles', we consider that there has been a change in community expectations and good industry practice since the 2010-15 regulatory period and the project is worth revisiting by the AER.

Therefore, CCP2 would encourage the AER and SA Power Networks to agree on an appropriate costing methodology for increased inspection rates and to provide for an efficient transition over the regulatory period to a higher inspection rate in nominated high-risk bushfire areas. We would expect SA Power Networks to be able to demonstrate progress on this in the next few years.

Recommendations:
The AER not accept SA Power Networks' revised proposal for additional funding for "no access' asset inspections as 2013-14 already includes enhanced inspection rates and there are no additional regulatory requirements.

The AER reconsider the merits of the proposed increase in asset inspection cycles from 10 years to 5 years in HBRAs as there is a general change in industry practice to higher asset inspection rates in these circumstances. SA Power Networks should be required to demonstrate an efficient transition process and efficient inspection costs.

- **Workplace health and safety (WHS)**:
SA Power Networks' step change proposal for WHS rests on claims of changing WHS regulations, changing expectations and its previous non-compliance with the relevant acts. The AER has rejected these additional expenditures.

Having considered the main changes in the WHS legislation, the AER's position on the WHS step changes appears reasonable. The main change appears to the move to a nationally consistent framework as adopted by the SA Government in the Work Health and Safety Act 2012 (SA) (WHS Act) in January 2013.

As stated by the AER, the WHS Act is substantially the same as the previous SA occupational health, safety and welfare legislation and SafeWork SA has confirmed this. For example, SafeWork SA states:[159]

> *Most of the Regulations* [the regulations under the WHS Act) *are consistent with the former occupational health safety and welfare legislation. However where there are new obligations, transitional periods are provided to support implementation by industry, business and workers.*

Therefore the WHS Act does not appear to pose a significant new or expanded obligation on SA Power Networks. What differences there are between the new and previous legislation concern matters that are not particularly relevant to SA Power

[159] SafeWork SA: "Work Health and Safety Transitional arrangements summary", December 2014. http://www.safework.sa.gov.au/uploaded_files/WHSTransitionalSummary.pdf. The regulations that commence on 1 January 2015 included recognition of asbestos removal licences in other jurisdictions and quarterly reports. Regulations that commence on 1 January 2016 include manifest of hazardous chemicals and notice that regulatory must be notified if manifest quantities to be exceeded. CCP2 does not regard these new burdens as significant in the context of the WHS requirements for SA Power Networks.

Networks. In any case, transitional provisions have been made to allow businesses to progressively adjust to the changes in an efficient way.

On 1 January 2013 the SA Government adopted the national approach in the SA WHS Act. The fact that SA Power Networks states that it did not comply with the requirements in the base year 2013-14, is rather concerning particularly given the transitional provisions provided additional time for businesses to adjust. However, this non-compliance is not, per se, a reason for additional expenditure allowances from 2015-16 onwards. Given SA Power Networks parent company also has ownership in the Victorian DNSPs, CitiPower and Powercor, national harmonisation should indeed lead to lower overall costs.[160]

As noted previously, there has been a very significant increase in the opex category of "corporate costs and other" since 2010 (See Figure 6.12). We would assume that this increase is reflected in the base year and provides adequate scope for managing the 'ups and downs' of regulatory compliance expenditure such as changes in the WHS law.

Recommendation:

The AER not accept the proposed step change for increased WHS obligations. The adoption of the national regulations in SA involves minimal change and the legislation allows for a transition period. The claim that SA Power Networks has not complied with the 2013 regulations by 2013-14 is concerning but not sufficient reason for higher opex allowance, and compliance costs should now be reducing.

- ***Energy Laws and regulations***:

  SA Power Networks' original proposal included step changes totalling $49 million for the RIN requirements, National Energy Retail Law (NERL), the NECF and demand side participation. Of these, the most significant step change claims related to RIN requirements and demand side participation. The AER rejected all of SA Power Networks' claims for step changes except for $1.3 million for the NECF change.

  Step change & RIN requirements: SA Power Networks original claim was for a step change allowance of $9 million ($2015) for RIN requirements. In its revised proposal, SA Power Networks' included a range of costs ($6.4 million and $16.6 million ($2015)) depending on whether the AER accepted aspects of its IT capex.

  The AER's rejections of a step change for RIN requirements over and above the allowance that forms part of the base year and output growth calculations seems reasonable.

[160] However, we recognise that at this point in time, Victoria is not a signatory to the national WHS agreement.

While we note SA Power Networks claims that the step change arises from moving from estimated RIN data in 2013-14 to actual RIN data (by 2015-16), we do not consider this warrants a step change per se.

In particular, SA Power Networks has not acknowledged that in the base years 2013-14, all the networks had to collect extensive historical data (whether best endeavours estimated data or actual data) going back to 2006 (and therefore going back into ETSA accounts). In addition, 2013-14 would have required SA Power Networks to establish a framework for ongoing collection of annual data.

Establishment costs are generally considerably greater than the ongoing costs or reporting. If anything, the costs of this annual updating should decline over time. Therefore although the 2015-16 requirements may be higher than 2013-14 (and we do not agree that they will necessarily be so), there should be ongoing and increasing savings over the whole 2015-20 RCP.

In its revised proposal, SA Power Networks has also indicated that its revised RIN costs will vary by a factor of $10 million (from $6.4 million to $16.6 million)[161] depending on the AER's acceptance or not of their proposed IT expenditure.

The AER should, therefore, examine SA Power Networks' claim very carefully. It is to be expected that an effective IT system will reduce costs of manual data collection, but it is difficult to know what the timing of that transition would be even if the AER approves the relevant capex. We note in passing that other IT upgrades in 2010-15 do not appear to have resulted in reductions in opex claims in SA Power Networks' current proposal.

SA Power Networks' claim regarding estimation of historical data does not clarify what proportion of the historical RIN data was estimated. It would be interesting to know the extent to which estimated data was used in the AER's benchmarking studies.

We would be concerned if this estimation process has distorted the benchmarking results and undermined the validity of the claim by SA Power Networks that it is amongst the most efficient business. A much more thorough examination of SA Power Networks' base year (2013-14) costs would be warranted if much of the benchmark data was estimated and 2013-14 costs were not, in reality, representative of actual costs.

Recommendations:

The AER not accept proposed step change for RIN reporting. The 2013-14 base year should include sufficient funds given it was an establishment year and the updated IT systems should further enhance opex efficiency.

[161] SA Power Networks, *Revised Regulatory Proposal*, July 2015, Table 8.26 and 8.27, pp 254 – 255.

Given SA Power Networks' claim that it has used estimated data for RIN reporting to date, the AER should further assess the accuracy of the historical benchmark studies, base year costing and capex planning.

Step change & demand side participation: With respect to demand side participation costs, we note that the AER rejected all of the $34 million ($2015) sought by SA Power Networks in its original proposal. The main elements of SA Power Networks' original proposal related to the opex cost of introducing cost-reflective network tariffs (demand based tariffs) by July 2017 and the costs of introduction of full competition in metering services (now required by the end of 2017).

The AER's view that SA Power Networks should not be compensated for the introduction of "cost-reflective" network tariffs in July 2017 appears reasonable given the step change criteria and the fact that such tariff designs are not new (although their wider application might be)

In the first instance, SA Power Networks is correct to say that the regulatory obligation in the NER requires DNSPs to adopt more "cost efficient" tariffs. However, the actual choice of tariff structures is up to the DNSP.

SA Power Networks has chosen to introduce demand tariffs, but time-of-use (TOU) tariffs for example, could also meet the requirements of the new rules and is well within the existing capabilities of SA Power Networks to manage. If SA Power Networks considers there is a benefit for it to move to demand tariffs (versus time-of-use) then the cost of this should be borne by SA Power Networks.

Also, CCP2 highlights that there is no regulatory obligation for SA Power Networks to 'rush into' the roll-out of cost reflective tariffs (whether demand based or TOU), as the AEMC has made very clear that should there be extensive consultation on the changes. The AEMC also states:[162]

> *This rule change will not actually set new network prices – that is a role for the networks themselves and the AER…*
>
> *[n]etworks are required to consider the impacts of price changes on consumers and could* ***gradually transition consumers to new prices over five years*** *or more if necessary*. [emphasis added]

If SA Power Networks chooses to bring in new tariffs at a faster rate and ahead of its regulatory obligations and its IT (CIS and CMS) upgrades, then this is a business choice and not a step change cost that should be passed through to customers.

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[162] See for instance, announcement by the AEMC Chairman, John Pierce: "Potential business savings from electricity reforms", 27 November 2014, http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements/Final/AEMC-Documents/News-announcement-business.aspx

Given SA Power Networks statements that its existing systems will not cope with the added data and tariff complexity, it is somewhat surprising for it to propose introducing these changes in network tariffs ahead of its upgrade of the CIS and CMS systems. It would seem more cost effective to minimise the introduction of new tariffs until the IT System upgrades occur rather than adapt an older system that has very limited life - unless the old CIS OV is already capable of meeting these requirements.

Importantly, the demand tariff will only be available to consumers with an appropriate meter type and the roll out of Type 4 or 5 meters can be expected to be a relatively slow process given that it is mandated for only a sub-set of customers. In addition, it is the retailers not the networks who will be directly billing mass-market customers on a demand tariff basis and it will be the retailers who are on the frontline of customer queries. The networks' task is relatively limited to billing retailers and this is a much smaller task.

Step change and NERL and NECF costs: All parties have agreed to remove the claim for step changes resulting from the planned ending of derogation from the NERL. The SA Government has advised that the derogation from the NERL will continue until 30 June 2020.[163]

The CCP2 also notes that the AER's approval of a step change claim ($1.3 million) with the introduction of new requirements under the NECF is reasonable. While we do not dispute the costs, CCP2 does question the consistency of the AER's approach in terms of regulatory "ups and downs" and, more particularly, the value of the AER ruling on each of these minor expenditures in the context of step changes.

SA Power Networks' has also referred to the step change costs of the proposed competition in metering rule change. However, there is still considerable uncertainty about the timing of the rule changes and the implementation requirements of any rule changes. It is not yet clear, therefore, what the final costs will be.

Therefore, CCP2 regards the opex costs related to competition in metering, if significant, should be subject to a pass through application when the details are better known. In the interim, SA Power Network can seek to reduce its future cost exposure by ensuring that its new IT systems are compatible with the policy option. It would be inefficient to update existing legacy systems prior to the planned changeover.

[163] The derogation related to Rule 90 of the NERL, which deals with the duration of planned interruptions. The derogation was due to expire on the 30 June 2015. However, the SA Government has extended the derogation period to 30 June 2020. See SA Government, "Submission to the AER on the SA Power Networks' regulatory proposal 2015-20", January 2015, p 12.

Recommendations:

The AER not accept step changes for the introduction of demand based network tariffs as this is business choice by SA Power Networks to introduce this type of tariff (versus for example a time of use network tariff) and to do so before the regulatory requirement and in advance of a new CIS and CRM system.

The AER only consider additional costs for competition in metering rule change when rule requirements and timing are clearer. If costs are sufficient, SA Power Networks can apply for a pass through of costs.

6.5.3.2. Capital Program Impacts Step Changes

SA Power Network has proposed a much expanded capex program including an extensive replacement program and upgrade of its IT and communication platforms. SA Power Networks has also claimed significant increases in opex to "manage" the expanded capex (see Figure 6.11).

The AER has rejected these claims. The AER's position appears to be reasonable, particularly where the project will generate savings to SA Power Networks.

However, there are a number of projects that the AER might reconsider in the light of updated business cases presented in SA Power Networks' revised proposal. If such projects do proceed, the CCP2 would expect to see very clear statements by SA Power Networks that set out when and how much savings will accrue to consumers.

Recommendation:

The AER not accept SA Power Networks' proposed step change associated with expansion of its capex program, particularly where this expansion leads to savings for SA Power Networks and electricity consumers would be paying twice for the initial capex and the incentive rewards.

There are a number of projects identified by SA Power Networks in this category, however, that warrant further examination by the AER

- **IT related step change**

  SA Power Networks originally proposed a total of 19 capital IT projects that would lead to an increase in opex and 3 capital IT projects that would lead to a reduction in opex, with a net opex step change increase of $44 million ($2015). The AER did not accept any of these step change changes.

  The AER's view is that:

  - if capital projects do not have a net benefit to the business they are not efficient unless driven by a recognised regulatory change; or
  - they are efficient, in which case SA Power Networks' opex costs will reduce and provide an opportunity for incentive payments to assist cost recovery.

Therefore, the AER rejected opex associated with capex projects that were designed to improve the efficiency of the business.

In general, the AER's assessment seems reasonable. As noted previously, he lack of transparency about the opex savings from previous IT investments raises significant concerns and it is pleasing that the AER is adopting the two assumptions listed above.

SA Power Networks' revised proposal significantly reduced the scope of its opex step change in line with the reduced scope of its capex IT program. The revised opex step change of $19 million ($2015) includes opex related costs for the proposed new data centre, enterprise security, SAP Foundation and replacement of the customer information system (CISOV). These proposals are discussed briefly below:

Step Change & Data Centre*:* The AER rejected the opex related to the new data centre as it regarded it as opex that is captured in the allowance for output growth. SA Power Networks responds that it is required by the increasing complexity and amount of data that needs to be collected under the various rule requirements and is more related to an efficient opex/capex trade off (as it moves to an "out-sourced" arrangement[164]).

There is some merit in SA Power Networks' data centre proposal. There is likely to be a significant expansion in data and requirements for greater processing speed and data security as a result of the 2017 rule changes for cost reflective tariffs and competition. Outsourcing of data centre facilities can provide a more flexible and sustainable solution than 'in-house' expansion.

It is therefore recommended that the AER investigate SA Power Networks' revised proposal and additional Business Case to confirm if the proposed outsourcing of the data centre is an efficient strategy (as planned). However, there should also be commensurate reductions over the regulatory period in SA Power Networks' own in-house staffing levels and accommodation costs. This is not apparent in SA Power Networks' revised proposal, but of course may assumed in the revised Business Case.

Therefore, we request the AER to investigate that the proposed step change is net of the savings in other areas of the business.

Recommendation:

The AER further investigate the business case for a new outsourced data centre. The case has some merit from a long-term sustainability point of view but it must be clear how savings will flow through to consumers in the future.

Step change & enterprise information security*:* The AER rejected SA Power Networks' initial proposal for a step change expenditure on enterprise information

[164] SA Power Networks, *Revised Regulatory Proposal*, July 2015, p 263.

security noting that SA Power Networks' business case did not provide a sufficient basis for additional expenditure allowance.

In its revised proposal, SA Power Networks has updated its business case and claims that this addresses the issues raised by the AER with its original business case.

In general, the risks around cyber security have increased and it is appropriate for SA Power Networks to adopt a cautionary approach to the issue. The risks are also likely to further increase over the 2015-20 RCP as there are more two-way flows of information across the network and between SA Power Networks' systems and consumers. It is essential for the successful roll out of smart meters (whether by networks or third parties), and for the implementation of other intelligent network systems generally, that consumers have absolute confidence in the integrity of the data systems.

As a result, there is potentially a case for a step change in information security costs. While not driven by specific regulatory requirements, there are wide spread expectations that businesses will upgrade the security of IT systems in response to emerging cyber threats. Given this, additional expenditure is not "discretionary" in nature.

It is therefore recommended that the AER review SA Power Network's revised business case to ensure that it is consistent with efficient expenditure. The adoption of new IT systems such as the new CIS and CRM should be accompanied by express user requirements to build in higher security standards. It is important that there is no double counting of these costs. That is, if the costs of additional security are part of the IT CIS/CRM replacements captured in non-network capex, then consumers need assurance that they are not also included as opex costs associated with upgrading the existing IT systems.

Recommendation:

The AER reconsider its position on a step change for enhanced information security. With increasing 2-way flows, there is greater risk of security breaches. There is also more general expectation by consumers that service providers will take positive actions to better protect the privacy of customer information.

However, the AER needs to ensure that SA Power Networks' proposal is efficient, particularly given the opportunities to build in additional security as part of the replacement of the CIS and CRM systems.

Step change and SAP Foundation*:* SA Power Network's claims it is implementing a major technical upgrade of its SAP hardware platform during 2015-16. SA Power Networks claims the upgrade is due to the age of the system, capacity limitations and the impact of the 2017 rule changes on cost reflective tariffs and metering competition. Associated with this, SA Power Networks claims the upgraded system will need additional opex of $2.3 million ($2015) for software maintenance and marginal increases in labour costs.

The AER has rejected this proposal on the basis that it does not provide opex step changes for upgrades and replacements of systems and software.

Notwithstanding SA Power Networks' argument that additional resources will be required to maintain the system, the AER's position in rejecting this step change expenditure is reasonable.

That is, the AER's view is correct from a policy point of view, as businesses in a competitive market absorb the opex (and capex) costs of system replacement all the time without increasing prices.

In addition, it is very likely that the base year 2013-14 also includes upgrades of various systems. It is also difficult to believe that, if the current SAP IT systems are as old as indicated by SA Power Networks, high maintenance and upgrade costs are likely to be part of the base year cost allowance and there would be costs savings from the having newer systems that offset other higher costs.

Recommendation:

The AER reject the proposed step change for SAP hardware upgrade costs. This project appears to be a standard part of business processes and it is likely there is an equivalent expenditures in the base year (2013-14) that offset any increased costs of the new systems.

Step change and CISOV replacement*:* The AER has accepted SA Power Networks' capex proposal to replace the existing CIS and CRM systems in the 2015-20 RCP as discussed in Section 5.

However, the AER has rejected SA Power Networks' proposal for additional opex allowance following the replacement of the system. The AER states that upgrades are only undertaken if the benefits outweigh the costs that the DNSP would otherwise face. That is: "total opex should not increase for efficiency improvements".[165] Unless driven by new regulatory requirements, the AER's total opex must be sufficient to allow the NSP to maintain the quality, reliability, security and safety of the distribution system and network services.[166] This should not require additional opex costs.

SA Power Networks has responded that there are additional opex costs in order to maintain the new CIS/CRM systems as the current CISOV system was "largely developed in house over a long period of time" and therefore SA Power Networks

[165] AER, *SA Power Networks Preliminary Determination 2015-20*, Attachment 7, April 2015 p 7—92.
[166] Ibid.

"has not had to pay associated software maintenance costs for a number of systems that form part of the current CISOV and CRM environment".[167]

It is not clear why SA Power Networks would claim it had lower opex using the old systems when it is also stating in its capex IT proposal that the existing CIS/CRM systems are aging and unsupported and therefore require additional maintenance and regular upgrading costs.

Given these apparently conflicting claims by SA Power Networks, it is appropriate that the AER review the revised business case provided by SA Power Networks to see if there is a reasonable basis for SA Power Networks' additional claims.

Recommendation:

The AER reject the proposed step change for additional opex following the changes to the CIS and CRM systems. Establishment and initial training and business redesign costs are usually capitalised. SA Power Networks is also avoiding the high costs of maintaining aging systems. A step change is not warranted given net costs and savings.

- **Telecommunications Step Change**

The discussion below addresses only those areas where SA Power Networks has submitted a step change claim in its revised proposal. Many of SA Power Networks' original step changes have not been included in the revised proposal.

Step change, mobile radio and communications*:* The AER has accepted as prudent and efficient opex, SA Power Networks' original proposal of $7.8 million to migrate to the South Australian Government Radio Network (SAGRN) and decommission the existing mobile radio network. In its revised proposal, SA Power Networks has increased the step change to $12.8 million.

CCP2 asks the AER to revisit the business case (which SA Power Networks has updated) to ensure that the expenditure is still prudent and efficient. It appears that that negotiations with the SA Government are still continuing over the cost and timing of migration of the mobile network. The AER should, therefore, investigate the risks around the proposal in terms of its final cost and deliverability.

Recommendation:

The AER revisit its previous acceptance of a step change opex associated with shift of provider for mobile radio and communications. SA Power Networks' revised proposal includes an increase in cost and negotiations appear to be ongoing with consequent delays to the project.

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[167] SA Power Networks, *Revised Regulatory Proposal 2015-20*, July 2015, p 267.

Non-network solution step change*:* SA Power Networks seeks a step change of $1.3 million for the ongoing management of its non-network solution at Bordertown that was approved under the RIT-D framework. SA Power Networks states that the costs of ongoing generation standby capacity and operational fees are on average $0.3 million per annum higher than in the base year 2013-15.

The AER has rejected this claim on the basis that it approves the total opex bundle not individual projects. In its revised proposal SA Power Networks suggests that the AER's approach will hinder the future expansion of non-network solutions under the RIT-D program as DNSPs will not be able to recover their efficient costs of the program over the lifetime of the project.

The amounts involved in this instance are relatively trivial and would normally be part of the "ups and downs" of expenditures rather than a step change. In addition, at least parts of the additional costs reflect forecasts of growth in demand and should therefore be captured in the output growth allowances.

Nevertheless, SA Power Networks has raised an important point of principle with respect to the operation of an approved RIT-D project and, in particular, the treatment of any verifiable cost changes over the lifetime of that project within the opex forecast assessment process. It is recommended that the AER further discuss this point of principle in the Final Determination.

Recommendation:

The Bordertown non-network solution raises more general issues on the question of recovery of increased costs associated with a project that is approved via a RIT-D. The AER to make clear on what basis can a DNSP get recovery for rising contract costs that have formed part of an accepted RIT-D project.

Step change and data quality*:* SA Power Networks claims it requires a step change in opex related to the enhancement of data quality such as the updating and correction of customer addresses. It based its claims on the fact that a review of data quality is required by the 2017 AEMC rule changes, the approved system upgrades of the CIS/CRM projects and general regulatory compliance requirements.

After at least 5 years of work on data quality, SA Power Network claims that there are still some 150,000 incorrect property addresses.[168]

The AER has rejected the claim on the basis that upgrading data quality would reduce costs rather than increase them as suggested by SA Power Networks.

The AER's decision is reasonable. Improvements in data quality will lead to significant reductions in operating costs over the 2015-20 RCP because it will reduce the level of error and need for manual investigations.

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[168] Ibid, p 272.

Moreover, the program is a continuation of an existing program and the costs would have been included in the base year costs (2013-14). It is concerning that SA Power Networks claims it still has 150,000 incorrect addresses out of a customer base of some 840,000 (18 per cent) and this suggests something is fundamentally wrong with its business processes for collecting and maintaining data.

SA Power Networks claims that it intends to intensify its program in the next few years and therefore requires an additional 11 FTE, declining to 7 FTEs in the latter half of the 2015-20 period. However, it is not clear if SA Power Networks has investigated more efficient ways (such as automating the process of correcting addresses using commercially available software) than employing over 35 man-years of labour costs.

However, it seems that much of this urgency of this expenditure is to do with SA Power Networks' discretionary program, the "Customer Service Strategy 2014-20". As such, if additional FTEs are required, then this is a matter for the business to allocate its total opex funds accordingly; it is not the basis for seeking additional step changes to maintain the reliability, quality and safety of the network and network services.

In any case, it does not seem appropriate that customers should now fund a step change in opex for what appears to be a failure by SA Power Networks to meet its fundamental business obligation to collect and maintain accurate customer records. This obligation is not new and the obligation precedes the 2017 rule changes and precedes SA Power Networks' desire to promote enhanced customer services.

Recommendation:

The AER reject SA Power Networks' revised proposal for data quality enhancement. This assessment of data quality should be a standard process and consumers should not have to fund rectification costs.

6.5.3.3. Customer Driven Initiatives Step Changes

There are three "customer initiated" programs that SA Power Networks claim are sought by customers and warrant a step change in opex. They are enhanced vegetation management, customer services and community safety. In total, these three programs account for $43 million ($2015) in additional opex, of which by far the largest is enhanced vegetation management ($33 million step change) in both bushfire and non-bushfire regions.

The AER has not accepted any of these additional expenditures. The proposed customer driven initiatives are discussed below. This paper briefly touches on SA Power Networks' proposals for a step change in customer service and customer safety. This is followed by a more extended review of the vegetation management step change

- **Customer service and community safety**

SA Power Networks has proposed a total opex of some $9.6 million on various customer service and community safety programs. SA Power Networks suggests that this step change is required to satisfy the conditions in its SRMTMP which requires SA Power Networks to undertake programs that raise awareness of the: "risks and obligations which are attendant with our electricity infrastructure the use of electricity and the role of SA Power Networks in that process"[169].

SA Power Networks also states that there is a requirement to keep consumers abreast of developments in the industry such as the 2017 rule changes. In addition, SA Power Networks argues that its CE program has identified that customers would value more information on energy matters.

The AER has rejected these step changes for additional opex allowances to provide enhanced customer service and address customer safety concerns.

The AER's conclusions on these matters seem reasonable. SA Power Networks has a responsibility to keep its customers informed on industry, usage and safety issues and there is already extensive information provided by SA Power Networks' on its own web site. This information is readily accessible and informative. Neither ESCoSA nor OTR have raised concerns that the information is inadequate. Therefore, it seems that SA Power Networks' current activities are sufficient to meet its regulatory obligations to keep customers informed.

To go beyond the information already provided would be a discretionary choice by SA Power Networks (taking into account the feedback from its customers), and therefore one that is not compensated for through the economic regulatory process. Such "self funded" community activities are reasonably normal for good sustainable businesses to undertake without adding to their prices.

In addition, there is already a considerable amount of relevant information available from other sources for consumers who are seeking more detailed industry related information and SA Power Networks can always point to these via links on its website.

For example, the major energy retailers, who are ultimately responsible for communicating retail pricing information to households and small businesses, also have considerable information on their websites about electricity use and energy savings. It is reasonable to expect SA Power Networks to work closely with these retailers to promote the new cost reflective tariffs and other industry changes. Retailers will also be interested in explaining the new contestable metering arrangements if they come into practice in the current RCP.

Independent information on the structure of the energy industry in SA and on efficient and safe energy use is also available on the web sites of ESCOSA, SafeWork SA, and the SA Government. These web sites also provide print ready documents to assist households, businesses and the electrical trades industry. Examples include:

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[169] Ibid, p 282.

http://www.escosa.sa.gov.au/electricity-overview.aspx

https://www.sa.gov.au/topics/water-energy-and-environment/electrical-gas-and-plumbing-safety-and-technical-regulation/electricity-and-gas-safety-for-consumers

http://www.safework.sa.gov.au/search.jsp?q=electricity

It is, of course, most important that information on electricity supply arrangements during bushfire events.

This paper includes a recommendation that the AER consider investments that will allow SA Power Networks to more effectively use its statutory rights to turn of electricity supply in the event of bushfires (see above). SA Power Networks web-site enables consumers to register to receive messages about loss of supply. There are also a number of media releases from the Country Fire Service (CFS), in conjunction with SA Power Networks, to better inform the public of the risk of loss of electricity supply.[170]

Given that the natural starting point for consumers concerned about bushfire risks in their region will be the State Government or the CFS, the SA Power Networks' strategy of working with the Government and CFS to explain the power risks during bushfires is likely to be more effective than 'going it alone'.

It would be useful, given the CE outcomes, for SA Power Networks to place a focus on this type of joint community communication, while also supplementing the existing bushfire risk material on its own web sites. Such an integrated approach would also be relatively low cost and likely to reach a larger audience.

Finally, SA Power Networks states that its research suggests consumers are seeking more information on the industry, electricity savings, electricity safety and so on. It is not clear if SA Power Networks explored with consumers in the CE program the extent to which they were aware of, and had utilised, the information that is already readily available from different places (as discussed above).

Our view is that in the context of a consumer research (such as a workshop or survey), consumers tend to say that they would like more information. However, further investigation indicates that they may not have been aware of, or had an interest in, the information that is already available. We would therefore urge extreme caution in allocating additional funds based on this type of research.

The consumer research is, however, useful in assessing how effectively existing funds are being utilised. It may be that small changes in SA Power Networks web site could achieve the same information and safety outcomes at a much lower cost.

[170] For example, see the CFS web site Media Release (dated 30/10/2013) during Bushfire Action Week. The SA Power Networks' spokesman explained the reasons and risks of electricity supply outage in a bushfire.
http://www.cfs.sa.gov.au/site/home/criimson/cfs_media_release_issued_30_oct_0650.jsp

Recommendation:

The AER reject a step change for enhancing customer service and safety information. These should be standard business practices and captured in the base year opex. In addition, consumers already have access to considerable range and sources of information already (not just from SA Power Networks) and it is important to manage a consistent and centralised system of customer advice during emergencies.

- **Vegetation management step change**

Reasons for SA Power Networks step change proposal*:* SA Power Networks' revised program includes a step change for vegetation management of $33 million, slightly higher than its original proposal because SA Power Networks has reduced its capex for bushfire risk areas. SA Power Networks' principle arguments for a step change in expenditure on vegetation management include:[171]

- The Electricity Act (section 55) requires SA Power Network to take "reasonable steps" to keep vegetation clear of power lines in accordance with the relevant regulations. These regulations are "mandatory and prescriptive" in their requirements;
- The understanding of what is "reasonable steps" changes over time, reflecting industry developments and changing expectations of electricity consumers; and
- The AER must have regard to the concerns of electricity consumers identified by the DNSP in the course of its engagement with consumers.[172]

The AER rejected SA Power Networks' original proposal for a number of reasons. The AER considered some aspects of the proposal related to "amenity" rather than the reliability, quality and safety of SA Power Networks' system and tree trimming activities. The AER considers that the question of enhanced amenity raises: "a broader policy issue and goes beyond our remit".[173]

There is also an option for local councils to sign up to Vegetation Clearance Agreements with SA Power Networks in non-bushfire areas to enhance amenity and/or alter the vegetation clearance responsibilities between the council and SA Power Networks.

The AER also considers that SA Power Networks' base opex provides a "sufficient source of funding for it to address safety and bushfire risks".[174]

In this context, the AER also addresses the question of SA Power Networks' WTP research. SA Power Networks set much store by the findings of the WTP research

[171] SA Power Networks, *Revised Regulatory Proposal 2015-20*, July 2013, p 275.
[172] NER, 6.5.6 (e)(5A).
[173] AER, *SA Power Networks Preliminary Determination 2015-20,* Attachment 7, April 2015, p 7-98.
[174] Ibid, p 7-99.

which they claim indicated that SA electricity consumers were willing to pay more for higher rates of tree removal and clearing in both bushfire and non-bushfire risk areas. The AER did not agree that the WTP research provided adequate support for a step change in opex of some additional $33 million ($2015).

SA Government's Submission to the AER*:* Before providing a response to the AER's PD and SA Power Networks' revised proposal, it is also important to highlight the views of the SA Government as expressed in its submission to the AER in January 2015. The SA Government's response provides an important perspective on the history and regulatory requirements in SA.

That is, it is the SA Government who determines the legal and regulatory requirements and who has in the past amended the Electricity Act and associate regulations in response to concerns about bushfire risk and vegetation management generally and the costs/benefits and efficiency of addressing these risks.

The SA Government opposed the vegetation management step change for the 2015-20 RCP. The SA Government also opposed the pass through of additional vegetation costs of $35 million ($2009-10) in 2013.[175] This 2012-13 pass through application by SA Power Networks was made in response to higher than forecast vegetation growth following the end of the millennium drought in 2010.

Nevertheless, in July 2013 the AER approved an amount of some $35 million as a pass through cost. The AER allocated step change costs to 2012-13, 2013-14 and 2014-15. However, there was no indication that the AER expected those costs to continue beyond 2014-15. Indeed, the AER included a declining annual pass through cost over that three-year period. The total impact of these allowed cost increases was included in the 2014-15 network tariffs only (with a NPV adjustment).

In both its response to SA Power Networks' pass through proposal and to its current regulatory proposal, the SA Government pointed to the natural variability in the SA climate between droughts and floods. The Government's submission noted that:[176]

> *On average, this combination of wet and dry conditions should result in a relatively consistent growth rate for vegetation over the period and it is not reasonable to assume vegetation growth will again be impacted by the unusual high rainfall of 2010 and 2011.*

The SA Government's 2015 submission on the proposed step change in vegetation costs concludes that the overall expenditure **should be limited to, and possibly lower than, the previous regulatory period allowance of $108.6 million on the basis of**: [177]:[178]

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[175] SA Power Networks had sought a pass through amount of $40.5 million ($2009-10). See AER, *Final Decision, SA Power Networks cost pass through application for vegetation management costs arising from an unexpected increase in vegetation growth rates*, July 2013, pp 27 & 34.

[176] South Australia Government, "Submission to SA Power Networks' regulatory proposal 2015-20", January 2015, p 10.

[177] Ibid, p 9.

- The $108.6 million was approved to allow SA Power Networks to catch up and become compliant with their regulatory obligations at that time given that the allowance for 2005-10 was only $43.3 million in total and was recognised as insufficient for SA Power Networks to comply with its scheduled vegetation management responsibilities;
- These obligations were amended in 2010 and are now less stringent than before 2010 with respect to vegetation management in non bushfire risk areas; and
- SA Power Networks has advised ESCoSA stated that it is on schedule to fully comply with the current Regulations by 30 June 2015.

The SA Government also expressed its concern that: [179]

> *[t]he results* [of the consumer engagement program] *do not align with the concerns expressed by South Australian electricity consumers at large.*

The SA Government noted, in particular, that they had received letters of concerns from customers following the pass through of the additional vegetation costs in 2014 electricity prices. More generally, the SA Government noted the increasing number of letters it had received from the community: "expressing concern with impact of escalating electricity prices".[180]

The SA Government also referred to stakeholder submissions to SA Power Networks' "Directions and Priorities Consultation Paper" (May 2014). The Government noted that a number of submissions to this Consultation Paper expressed concern with the results of the consumer engagement process thus far, stating that: "the impacts on consumer bills of the initiatives [presented by SA Power Networks] were not expressly revealed". [181]

As a result of these concerns, the SA Government requested the AER to consider whether SA Power Networks' proposed expenditures (arising from the customer engagement research: [182]

> *[a]re prudent while bearing in mind the community's real concern about the impact of electricity prices on household incomes and business operations.*

The Government's observations are consistent with the feedback that CCP2 has received over the last nine months during its meetings with consumer representatives concerning aspects of SA Power Networks' CE program.

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[178] See ibid, pp 9-10.

[179] Ibid, p 12.

[180] Ibid.

[181] Ibid, p 13.

[182] Ibid.

Local Governments' submissions on the vegetation step change*:* While most submissions to SA Power Networks' proposals did not agree with the proposed step change in vegetation expenditure, a number of local councils and the Local Government Association of South Australia did support the proposal. It is acknowledged that the councils have a legitimate interest in the issue.

The AER notes that in many instances, the councils' concerns relate to the "amenity" of the tree-cutting program, particularly in the non-bushfire risk areas.

That is, councils were concerned that the tree trimming practices adopted by SA Power Networks in order to comply with the Vegetation Clearance regulations affected the health of the street trees and the visual appearance of the street. Suggestions to address this include relatively minor cost items such as employing professional arborists and more expensive solutions such as more regular pruning of trees.[183]

As noted above, there is provision in the relevant legislation and regulations for councils to sign up to Vegetation Clearance Agreements with SA Power Networks. These Agreements provide a council with an opportunity to direct SA Power Networks to undertake a different inspection and cutting regime. There are also provisions for a council to opt to take responsibility for management of vegetation around low voltage lines and to make payments to/from Council to SA Power Networks in accordance with these actions.

This provides considerable flexibility for councils to adjust SA Power Networks' local vegetation program to better and more directly address the concerns of their local citizens on amenity and/or bushfire risk.

However, SA Power Networks' revised proposal states, in response to the AER's discussion on this option, that:[184]

> *With respect to funding of vegetation management initiatives, SA Power Networks is aware that there is provision in section 55A of the Electricity Act for local councils to assist SA Power Networks in funding vegetation management programs by entering into vegetation clearance schemes with us. However,* ***in practice, local councils have not been prepared to do so or have only done so on a very limited basis.*** [emphasis added]

SA Power Networks then proceeds to claim: [185]

> *SA Power Networks is of the view that* ***it is not reasonable*** *to wait until councils are willing to enter into funding arrangements under the Electricity Act in relation to vegetation management. If that was the position taken by SA Power Networks, the significant concerns of consumers in relation to visual amenity and safety*

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[183] This would enable SA Power Networks to cut back vegetation less severely as it would only have to allow for a 2 year grow back rather than the existing 3 plus years.
[184] SA Power Networks, *Revised Regulatory Proposal 2015-20,* July 2015, p 278.
[185] Ibid, 279.

*aspects of vegetation management may well never be addressed and it is not appropriate for SA Power Networks to simply say that it is someone else's responsibility given **that it clearly has obligations to appropriately maintain vegetation around power lines**.* [emphasis added]

These conclusions drawn by SA Power Networks are somewhat concerning as discussed in the following sections of this advice.

Conclusions on proposed vegetation management step changes

In its 2013 review of SA Power Networks' pass through application, the AER accepted that there were material incremental vegetation management costs incurred by SA Power Networks following the end of the drought. The AER approved the pass through application as summarised in Table 6.3. These costs were **in addition** to the $108.6 million allowed for vegetation management in 2010 for the 2010-2015 RCP.

Table 6.3: AER assessment of pass through costs for vegetation management

($m nominal)	2012-13	2013-14	2014-15
Smoothed revenue requirement	761.9	825.7	851.5
Materiality threshold (1%)	7.6	8.3	8.5
Proposed pass through amount	14.9	16.2	12.1
Approved incremental opex	14.9	11.4	9.4

Source: AER, Final Decision, SA Power Networks cost pass through application for vegetation management costs, July 2013, Table 4.2, p 25. Note, the table is in nominal dollars, the total in real $2009-10 was $13.8 m, $10.3 m and $8.2 m respectively ($35.1m in total)

The AER's original allowance of $106.8 million for 2010-15 was based on the expenditure in the base year of 2008-09. SA Power Networks' Economic Benchmarking spread sheet indicates that SA Power Networks had spent a total of $22 million ($ nominal) in 2008-09 on vegetation management and that this amount was around 45 per cent more than the average of the previous three years ($15 million nominal) even though drought conditions still prevailed.

The pass through decision added around $7 million per year (averaged over 5 years 2010-2015). However, as indicated in Table 6.3 above, the AER estimated the opex impact in a three-year window of 2012-13 to 2014-15.[186] It is likely therefore that the cost for the total vegetation opex (including the pass through) in 2013-14 base year was around $40 million[187] of which some $11.4 million was related to the special incremental

[186] Noting that the actual revenue was collected from consumers in 2014-15 year only.

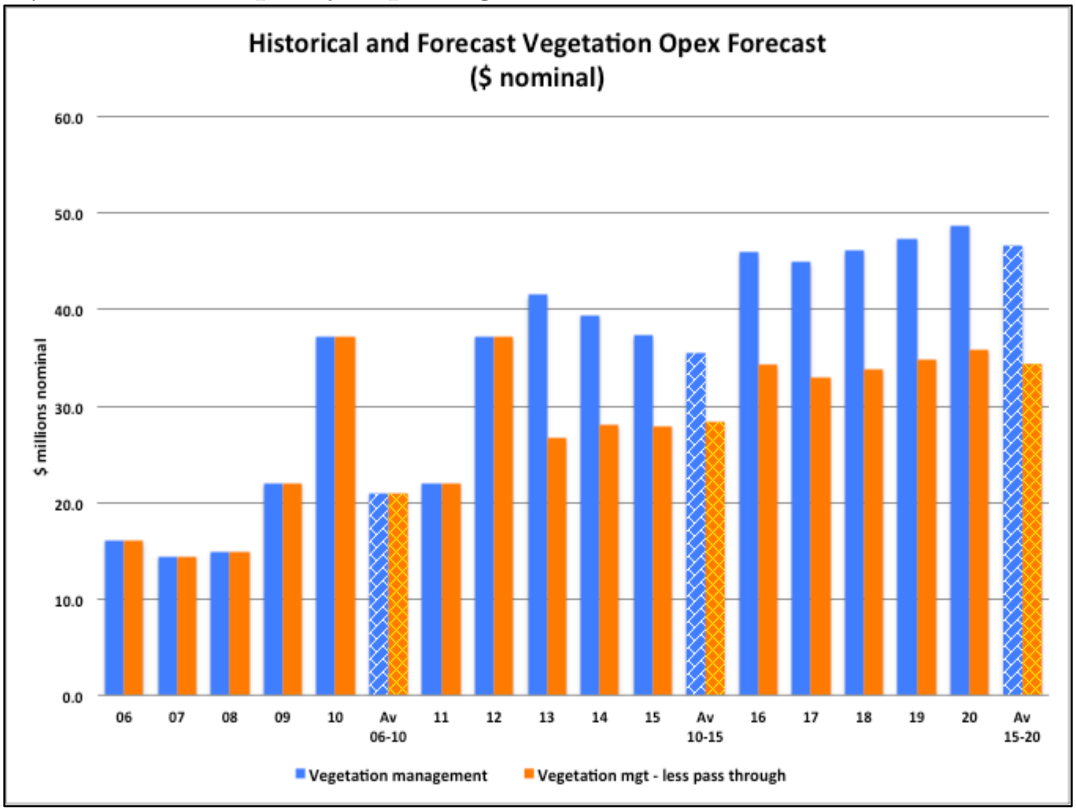
[187] Calculated as the average of 2012-13 (from the economic benchmarking spreadsheet, table 3.1.1) and 2014-15 (from SA Power Networks Reset RIN data proposal). At this stage, it is not clear from the Reset RIN or the Economic Benchmark report what that the 2013-14 actual vegetation management opex was.

pass through costs. These incremental costs allowed by the AER were fully recovered by the end of 2014-15.

On this basis it would seem more appropriate that there is a **step down in 2015-16** of some $11.4 million corresponding to the AER's pass through cost allowance in Table 6.3.[188] If this adjustment had been made, then a reasonable estimate of SA Power Networks required **total vegetation allowance would be around $172 million ($ nominal), or an average of around $34 – 35 million per year ($ nominal).**

Figure 6.13 below provides an illustration of this assessment. The historical figures are based on SA Power Networks Economic Benchmarking RIN (in nominal dollars). The figure for 2013-14 is an estimate. The forecasts vegetation costs are taken from SA Power Networks' Revised Reset RIN, including an adjustment for the AER's 2013-14 incremental vegetation allowance arising from the cost pass through allowance (Table 6.3).

Figure 6.13: Historical and SA Power Networks' forecast vegetation opex and adjustment for temporary step change in 2013-14 costs, $ nominal



Source: SAPN Economic Benchmarking Spreadsheet, SAPN Revised Reset RIN (table 3.2), CCP2 analysis. Note, the benchmarking data is in nominal dollars and the Revised Reset RIN has been converted to nominal dollars on basis of 2.5% pa inflation for the forecast period.

The assessment derived in this way generates a slightly lower total vegetation opex than the AER's assessment approach may deliver. That is, assuming no adjustment to

[188] It is acknowledged that actual expenditure in 2013-14 might be different than the allowance, and adjustments should be made accordingly.

2013-14 and no step change allowance, the estimated cost from the AER is approximately $184 million real $2015.[189]

Nevertheless, the figure derived from removing the vegetation pass through cost is substantially above the 2010-15 allowance once the impact of the one-off step change is removed (as per Figure 6.13).

Given a return to a normal dry/wet cycle, and given that SA Power Networks states that it will have caught up on the backlog of vegetation management, this allowance of $172 million ($ nominal, or around $160 million in $2015) should be sufficient for SA Power Networks to maintain the reliability, quality and safety of the network and network services, while addressing some consumer concerns.

This suggestion is also closer to the SA Government's expectations regarding an appropriate opex allowance for 2015-20 and accords with the various submissions that wish to see some constraint on (further) increases in vegetation opex.

However, these conclusions are not in accord with a number of submissions from local councils and the SA Local Government Association as these organisations support SA Power Networks' step change proposal.

It is not clear if the councils are fully aware that SA Power Networks has already had substantial increases in its vegetation allowances and, given a relatively stable weather cycle of wet and dry years, is in a position to place greater focus on amenity and safety issues as part of its day to day responsibilities for vegetation clearance.

In addition, SA Power Networks' commentary above suggests that the councils have been reluctant to assist in funding additional expenditure despite the flexible options provided under the regulations to assist councils address local preferences.

The councils also need to consider that any increases in prices that flow from such additional expenditures in their local areas will (in the absence of council funding contributions) be borne by the whole of the SA community of electricity users. Even if SA Power Networks received an additional allowance for amenity (and this is not recommended) it would still need to prioritise which regions it addresses and how much it commits to that region, so that individual councils may still not get their preferred outcome for their ratepayers.

In terms of SA Power Networks' comment that it is not reasonable to wait for councils to commit to these Agreements with it, the response must be that it is absolutely reasonable. Different local councils will have different priorities and if some councils want a higher standard of vegetation management in their region than is required to deliver a reliable, quality and safe electricity network and network services, then it is appropriate that that council contributes to this rather than put that burden on all electricity consumers in the state.

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[189] Using SA Power Networks forecast less the proposed step change for vegetation of $33 million ($2015).

To put it bluntly, there is no reason why struggling electricity consumers in (say) Whyalla should pay more for their electricity so that urban consumers can enjoy a better treescape.[190] In like vein, if local councils are not willing to take up the opportunity provided by the flexible Vegetation Management Agreements, then why is it appropriate to ask all electricity consumers in the state to fund these local amenity improvements?

However, as indicated above, this is not to say that SA Power Networks should not pay attention to its consumer research and consider ways that it can improve its vegetation management activities to align with their concerns. It can look at ways it can do so within its "allowance", it can do so as a "good corporate citizen", or it can do so by seeking alternative funding sources.

Overall, however, the CCP2 considers local councils have considerable expertise in this area and if additional amenity is desired, it would be useful for local councils to continue to work with SA Power Networks and develop effective Vegetation Clearance Agreements.

It is also important that SA Power Networks understands the councils' perspectives and uses the opportunity available to it with historically high capex and opex allowances to enhance its vegetation management procedures.

Recommendation:

The AER reject the step change for vegetation management. The 2013-14 base year already includes a large "step up" as a result of the vegetation pass though process. If this is carried forward then this is more than sufficient for SA Power Networks to continue and enhance its vegetation procedures.

6.5.4 Summary of Opex Step Changes

Table 6.4: Summary of Opex Step changes

	Parameter	AER Preliminary Determination	SAPN's revised proposal	Comments
Legal & Regulatory Step Changes	Asset Inspections	Reject SAPN's original proposal	Disagree with AER, needs to comply with SRMPTMP	Partly agree with AER. Consider some merit in move

[190] Note, we are not talking here about meeting the regulatory requirements for vegetation clearing related to providing a reliable, quality and safe network, they are what they are and SA Power Networks must meet those for all sectors of the SA community The comment relates to the more discretionary aspects of SA Power Networks vegetation clearance activities.

				from 10 to 5 year asset inspections in HBRA
	Workplace Health & Safety	Reject SAPN's original proposal	Disagree with AER due to reg. changes & non-compliance	Agree with AER. Reg. changes not significant enough
	Energy laws & regulations	Reject over 95% of original proposal	Disagree with AER but cut back from original proposal	Agree with AER but suggest "competition in metering" may be pass through post 2017
Capital Program Impacts Step Changes	Information Technology	Reject SAPN's forecast of additional opex to match capex	SAPN disagrees, but cut back opex to reflect revised capex	Agree largely with AER. May be some merit in data centre & security step change opex; AER to re-examine business cases. Expect tangible benefits for customers from capex.
	Mobile Radio	AER agrees with SAPN's original proposal	SAPN submits higher cost than original proposal	Agree with AER, but seek check on higher cost
	Other step changes	AER did not allow any other step changes	SAPN accepts most, but proposes original expenditure for data quality	Agree with AER. Data quality should be normal business practice
Customer Driven Initiatives	Vegetation management	AER rejects SAPN's original proposal	SAPN disagrees, submits approximately same amount as original proposal	Agree largely with AER. SAPN 2013-14 base year includes pass through cost included & should be an adjustment for

				this
	Customer Services & community safety	AER rejects SAPN's original proposal	SAPN disagrees, cites CE support and regulatory obligations	Agree with AER. Should be part of normal business and costs shared with other authorities.